DIRECT TESTIMONY AND EXHIBIT OF

ANTHONY M. SANDONATO

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2023-9-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Anthony Sandonato. My business address is 1401 Main Street, Suite 900, Columbia, South Carolina, 29201. I am employed by the State of South Carolina as the Deputy Director of the Energy Planning and Emerging Technology Division of the Office of Regulatory Staff ("ORS").

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I received my Bachelor of Science in Nuclear Engineering from North Carolina State University in 2011. Prior to my employment with ORS, I was employed as an analyst with a global professional, technology, and marketing service firm working with large investor-owned utilities on energy efficiency program design and implementation. I joined ORS in 2016 as a Regulatory Analyst and worked on electric, natural gas, water and wastewater regulatory proceedings. In this role I participated in rate cases, annual fuel proceedings, purchase gas adjustment cases, and rate stabilization act proceedings with a focus on system planning, operation, and design. In 2019, I was promoted to Senior Regulatory Manager in the Energy Operations Division and focused on electric and natural gas utilities. In this role I oversaw ORS's review of utility resource planning and utility system modeling in addition to my previous responsibilities. In December 2021, I was promoted to my current position and developed the Energy Planning and Emerging

Technology Division which focused solely on utility planning and emerging technology. In October of 2022 the Energy Planning and Emerging Technology Division took on the responsibilities of the Energy Efficiency and Renewables Division and is now responsible for the review of renewables, energy efficiency and demand side management programs, utility resource planning and emerging technology programs.

Q. HAVE YOU TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes. I have previously testified before the Commission on several occasions.

Q. WHAT IS THE MISSION OF ORS?

A. ORS represents the public interest as defined by the South Carolina General Assembly as:

> [T]he concerns of the using and consuming public with respect to public utility services, regardless of the class of customer, and preservation of continued investment in and maintenance of utility facilities so as to provide reliable and high-quality utility services.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING AND HOW DOES YOUR DIRECT TESTIMONY REPRESENT THE PUBLIC INTEREST?

A. The purpose of my Direct Testimony is to set forth and support ORS's recommendations resulting from the examination and review of Dominion Energy South Carolina, Incorporated's ("DESC" or "Company") 2023 Integrated Resource Plan ("2023 IRP") and associated filings in this docket to determine compliance with certain subsections of S.C. Code Ann. § 58-37-40 ("Section 40"). By reviewing the 2023 IRP to determine compliance with Section 40, my Direct Testimony represents the public interest.

Q. DID ORS RETAIN ANY EXPERT WITNESSES FOR THIS PROCEEDING?

Yes. ORS retained two expert witnesses for this proceeding to assist in the review and analysis of the Company's 2023 IRP: Philip Hayet, Vice President and Principal and Leah J. Wellborn, Manager of Consulting. Both expert witnesses are employed with the consulting firm J. Kennedy and Associates, Inc. ("Kennedy").

Q. WAS THE EXAMINATION AND REVIEW OF DESC'S 2023 IRP FILINGS PERFORMED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes. The examination and review to which I testify was performed by me or under my supervision.

Q. PLEASE EXPLAIN EXHIBIT AMS-1.

A. Exhibit AMS-1 is the Review of Dominion Energy South Carolina, Inc.'s 2023 Integrated Resource Planning Report (the "Report"). The Report was developed for ORS by Kennedy and provides a detailed analysis of DESC's 2023 IRP. The Direct Testimonies of ORS Witnesses Hayet and Wellborn discuss their respective reviews, analyses and recommendations.

Q. SECTION 40 REQUIRES ELECTRIC UTILITIES IN THE STATE WITH ONE HUNDRED THOUSAND OR MORE CUSTOMER ACCOUNTS TO PREPARE AND SUBMIT AN IRP TO THE COMMISSION EVERY THREE YEARS. IS THIS REASONABLE?

A. Yes. A tri-annual IRP process is reasonable, consistent with other states in the Southeast, and aligns with best practices in utility planning. For example, Georgia requires "at least every three years […] as may be determined by the commission, each utility shall file with the commission an integrated resource plan".[1] North Carolina requires utilities to

[1] O.C.G.A. § 46-3A-2(a).

file a current integrated resource plan every two years.[2] Virginia requires that "each electric utility shall file an updated integrated resource plan by May 1, in each year immediately preceding the year the utility is subject to a triennial review filing."[3]

The Commission and other interested parties will be informed how the Company's preferred plan is impacted by updated assumptions during the IRP Annual Updates.

Q. PLEASE DETAIL THE CRITERIA BY WHICH YOU EVALUATED THE COMPANY'S 2023 IRP.

A. ORS relied on the requirements provided in S.C. Code Ann. § 58-37-40(B)(1)**,** which requires an IRP for an electrical utility include the following:

> (a) a long-term forecast of the utility's sales and peak demand under various reasonable scenarios;
> (b) the type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;
> (c) projected energy purchased or produced by the utility from a renewable energy resource;
> (d) a summary of the electrical transmission investments planned by the utility;
> (e) several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following:
>
> > (i) customer energy efficiency and demand response programs;
> > (ii) facility retirement assumptions; and
> > (iii) sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;
>
> (f) data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;
> (g) plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan;

[2] Rule R8-60(h)(1) of the Rules and Regulations of the North Carolina Utilities Commission.
[3] Va. Code of Laws § 56-599(A).

(h) an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs; and,
(i) a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.

Q. DOES THE COMPANY'S 2023 IRP COMPLY WITH SECTION 58-37-40(B)(1)?

A. Yes. The Company's 2023 IRP, as filed with the Commission, includes all of the elements required in Section 58-37-40(B)(1). Each element and a corresponding analysis of DESC's 2023 IRP compliance is discussed in detail in the Report contained in Exhibit AMS-1.

Q. PLEASE SUMMARIZE S.C. CODE ANN. § 58-37-40(C).

A. To determine whether the IRP is the most reasonable and prudent means of meeting energy and capacity needs, section 58-37-40(C) provides that the Commission, in its discretion, shall consider whether the plan appropriately balances the following factors:

(a) resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins;
(b) consumer affordability and least cost;
(c) compliance with applicable state and federal environmental regulations;
(d) power supply reliability;
(e) commodity price risks;
(f) diversity of generation supply; and
(g) other foreseeable conditions that the commission determines to be for the public's interest.

Q. PLEASE SUMMARIZE ORS'S RECOMMENDATION RELATED TO THE COMPANY'S 2023 IRP.

A. ORS recommends the Company address eight issues in Rebuttal Testimony and seven items in the Stakeholder Working Group to improve future IRPs. Each ORS recommendation listed below is discussed in more detail in the Report and the Direct Testimony of ORS Witnesses Hayet and Wellborn. The specific modifications recommended by ORS including the corresponding item number as found in the Executive Summary of the Report are listed in the table below.

Item	ORS Recommendations	2023 IRP or Future IRP	Person Responsible
A1	Reserve Margin - DESC should fully document the extreme winter weather statistical analyses, and demonstrate that the models reasonably reflect winter loads during extreme low temperatures in future IRPs. The Company should also report on the Company’s findings in the Stakeholder Working Group.	Future	Hayet
B1	Load Forecast - DESC should perform more detailed analyses to assess the reasonableness of its Residential and Commercial class peak load forecasts in future IRPs, and in particular, the Company should provide support for the assumption that the average peak load per residential and commercial customer will remain essentially constant over the forecast horizon.	Future	Wellborn
B2	Load Forecast - DESC should provide details in Rebuttal Testimony on the EV rate designs and load management programs the Company considers to mitigate EV impacts on peak demand and capacity need.	2023 IRP	Wellborn
C1	DSM - DESC should file the results of corrected High and Low DSM Sensitivity Cases in Rebuttal Testimony.	2023 IRP	Wellborn
D1	Commodity Forecasts - All commodity forecasts, including CO_2 forecasts, should continue to be discussed in the Stakeholder Working Group. ORS’s recommendation regarding CO_2 forecasts is based on the fact that a CO_2 tax has never been imposed at the Federal level or by the State of South Carolina, and there are renewable market incentives that could justify a lower price forecast, whereas pending CO_2 rules under the Clean Air Act (“CAA”) could justify a higher price forecast.	Future	Hayet
E1	Renewables - DESC should discuss the appropriate modeling of integration costs for renewable resources in the Stakeholder Working Group.	Future	Wellborn
E2	Renewables - DESC should discuss potential impacts of the proposed Environmental Protection Agency (“EPA”) CAA Section 111 Regulation of Greenhouse Gas (“GHG”) Emissions from Fossil Fuel-Fired Electric Generating Units (“EGU”) rule change in Rebuttal Testimony.	2023 IRP	Hayet
F1	Retirements/New Resources - DESC should provide justification explaining the reasonableness of the significant cost increases associated with generic CT resources in Rebuttal Testimony.	2023 IRP	Hayet

Item	ORS Recommendations	2023 IRP or Future IRP	Person Responsible
F2	Retirements/New Resources - DESC should explain in Rebuttal Testimony why the CC heat rate assumptions are not overly optimistic and confirm this is the technology the Company is considering for the Joint CC unit.	2023 IRP	Hayet
F3	Retirements/New Resources - DESC should perform one additional modeling sensitivity of the Reference Case assuming higher battery costs based on the market data provided in the RFP conducted in Docket No. 2021-93-E. The Company should also correct the fixed Operating and Maintenance ("FO&M") costs modeling error identified by Sierra Club. This information should be provided when the Company files Rebuttal Testimony.	2023 IRP	Hayet
F4	Retirements/New Resources - DESC should provide additional clarification of the Transmission Impact Analysis ("TIA") Cases, and further explain how the results will be used to make a final decision about the replacement capacity selected for the Wateree units in Rebuttal Testimony.	2023 IRP	Hayet
F5	Retirements/New Resources - DESC should provide additional support for the capital and O&M costs modeled assuming continued operation at Wateree and Williams in Rebuttal Testimony.	2023 IRP	Hayet
G1	PLEXOS Benchmarking - DESC should be required to conduct production cost model benchmark studies on an on-going basis, such as once every three years ahead of Comprehensive IRP proceedings, and the Company should discuss benchmarking results in the Stakeholder Working Group.	Future	Wellborn
G2	Risk Analysis - DESC should evaluate additional ways to incorporate robust risk analyses such as assessing portfolios across multiple planning scenarios. As part of this evaluation, the Company should consider the importance of making near-term decisions that feed into the Company's Action Plan. The Company should discuss this topic in the Stakeholder Working Group.	Future	Hayet
G3	Transmission - DESC should update the Commission on the transmission impacts and the natural gas pipeline capacity availability associated with unit retirements and new resource decisions. The Company should file the results of the 2023 TIA Study, including all workpapers and supporting documentation when it becomes available.	Future	Hayet

Q. WILL YOU UPDATE YOUR DIRECT TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

A. Yes. ORS fully reserves the right to revise its recommendations via supplemental testimony should new information not previously provided by the Company, or other sources, become available.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

OFFICE OF REGULATORY STAFF
ORS
SOUTH CAROLINA

Review of Dominion Energy South Carolina, Incorporated's 2023 Integrated Resource Plan Docket No. 2023-9-E

South Carolina
Office of Regulatory Staff

June 27, 2023

Review of Dominion Energy South Carolina, Incorporated's 2023 Integrated Resource Plan

Pursuant to Section 58-37-40, South Carolina Code of Laws

June 27, 2023

Prepared by the South Carolina Office of Regulatory Staff
and
J. Kennedy and Associates, Inc.

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I. Executive Summary

The South Carolina Office of Regulatory Staff ("ORS") provides this Report in review of Dominion Energy South Carolina, Inc.'s ("DESC" or the "Company") 2023 Integrated Resource Plan ("2023 IRP") filed January 30, 2023, in Docket No. 2023-9-E. ORS, with the assistance of J. Kennedy and Associates, Inc., evaluated DESC's 2023 IRP to determine if the statutory requirements of S.C. Code Ann. § 58-37-40 ("Section 40"), as amended by the South Carolina Energy Freedom Act ("Act 62"), and the requirements of the Public Service Commission of South Carolina's ("Commission") Order No. 98-502 were met by DESC.

Act 62 was signed into law by Governor McMaster on May 16, 2019 and established new IRP requirements. Section 40 has specific information requirements that address the peak load and energy forecasts, reliability, new resource alternatives, renewable resources, and existing resource retirements. Section 40 also contains other substantive and procedural requirements. Section 40 requires the Commission to "approve an electrical utility's . . . integrated resource plan if the [C]ommission determines that the proposed integrated resource plan represents the most reasonable and prudent means of meeting the electrical utility's . . . energy and capacity needs as of the time the plan is reviewed."[1]

DESC's 2023 IRP is the second comprehensive IRP submitted by DESC, and since 2020, DESC implemented major changes in planning processes. In 2022, DESC conducted a Coal Retirement Study pursuant to Commission Order No. 2020-832.[2] The Coal Retirement Study has informed the 2023 IRP, and the Company proposes to retire the Wateree and Williams coal units by 2030. The Company evaluated replacement resources for when the coal units retire and now considers the possibility of constructing a jointly owned combined cycle ("CC") resource with the South Carolina Public Service authority ("Santee Cooper"). DESC also considered the need to retire thirteen (13) old natural gas combustion turbine ("CT") units, and a steam unit. One of the outcomes of the IRP process is that the Commission established a requirement that DESC rely on competitive procurement processes to acquire new resources.[3]

The Commission required DESC to facilitate a Stakeholder Working Group process to discuss planning issues and obtain feedback from interested parties on "best" utility industry planning practices. Since the 2020 IRP, the Company hosted eleven (11) Stakeholder Working Group meetings and discussed numerous topics at the request of stakeholders and the Commission.

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[1] S.C. Code Ann. § 58-37-40(C)(2).
[2] The Coal Retirement Study will be discussed in more detail below.
[3] Commission Order No. 2021-429, Ordering Paragraph 6.

The Company replaced its legacy production cost model with a new widely used production cost model known as the PLEXOS Integrated Energy Model ("PLEXOS"). In addition to using PLEXOS for production cost modeling, DESC addressed a Commission requirement from the 2020 IRP to begin using resource optimization logic, which is a feature in the PLEXOS model. The Company performed certain studies that were incorporated in the 2023 IRP. This includes a new Reserve Margin Study based on a new modeling methodology performed by Astrapé, a new Market Potential Study performed by ICF Resources, LLC ("ICF"), and an Electric Vehicle ("EV") Study performed by Guidehouse Inc. ("Guidehouse").

The 2023 IRP highlights the important and time sensitive decisions that must be made by the Company, including decisions about the retirement of the Wateree units and replacement units needed to maintain System reliability. Specifically, the economic justification to retire Wateree is based on the fact that the Company would avoid the cost of compliance with the Environmental Protection Agency's ("EPA") Effluent Limitation Guideline ("ELG") regulation upgrades. However, if the Company is unable to acquire replacement resources by the time it plans to retire Wateree (end of 2028), the Company may be forced to construct the ELG upgrades. A final decision on the Wateree retirement is premised on the completion of transmission analyses, a Request for Proposal ("RFP"), and the selection of replacement resources for Wateree. The timeline for the Company to decide about the Wateree retirement versus making the necessary ELG compliance upgrades is limited, and customers may be subject to a costly outcome if the decision is not cautiously considered.

ORS identified issues the Company should address either in Rebuttal Testimony or in future Stakeholder Working Group sessions prior to the 2024 annual IRP Update. ORS provides the following summary of recommendations, and provides additional details in subsequent sections of this report.

Reserve Margin Recommendations

A1. DESC should fully document the extreme winter weather statistical analyses, and demonstrate that the models reasonably reflect winter loads during extreme low temperatures in future IRPs. The Company should also report on the Company's findings in the Stakeholder Working Group.

Energy and Demand Forecasts Recommendations

B1. DESC should perform more detailed analyses to assess the reasonableness of its Residential and Commercial class peak load forecasts in future IRPs, and in particular, the Company should provide support for the assumption that the average peak load per residential and commercial customer will remain essentially constant over the forecast horizon.

B2. DESC should provide details in Rebuttal Testimony on the EV rate designs and load management programs the Company considers to mitigate EV impacts on peak demand and capacity need.

Energy Efficiency (“EE”) and Demand Side Management (“DSM”) Recommendations

C1. DESC should file results of corrected High and Low DSM Sensitivity Cases in Rebuttal Testimony.

Commodity and Carbon Dioxide (“CO_2”) Price Recommendations

D1. All commodity forecasts, including CO_2 forecasts, should continue to be discussed in the Stakeholder Working Group. ORS’s recommendation regarding CO_2 forecasts is based on the fact that a CO_2 tax has never been imposed at the Federal level or by the State of South Carolina, and there are renewable market incentives that could justify a lower price forecast, whereas pending CO_2 rules under the Clean Air Act (“CAA”) could justify a higher price forecast.

Renewable Energy and Energy Storage Forecast Recommendations

E1. DESC should discuss the appropriate modeling of integration costs for renewable resources in the Stakeholder Working Group.

E2. DESC should discuss potential impacts of the proposed Environmental Protection Agency (“EPA”) CAA Section 111 Regulation of Greenhouse Gas (“GHG”) Emissions from Fossil Fuel-Fired Electric Generating Units (“EGU”) rule change in Rebuttal Testimony.

Retirements and New Resource Decisions Recommendations

F1. DESC should provide justification explaining the reasonableness of the significant cost increases associated with generic CT resources in Rebuttal Testimony.

F2. DESC should explain in Rebuttal Testimony why the CC heat rate assumptions are not overly optimistic and confirm this is the technology the Company is considering for the Joint CC unit.

F3. DESC should perform one additional modeling sensitivity of the Reference Case assuming higher battery costs based on the market data provided in the RFP conducted in Docket No. 2021-93-E. The Company should also correct the fixed Operating and Maintenance ("FO&M") costs modeling error identified by Sierra Club. This information should be provided when the Company files Rebuttal Testimony.

F4. DESC should provide additional clarification of the Transmission Impact Analysis ("TIA") Cases, and further explain how the results will be used to make a final decision about the replacement capacity selected for the Wateree units in Rebuttal Testimony.

F5. DESC should provide additional support for the capital and O&M costs modeled assuming continued operation at Wateree and Williams in Rebuttal Testimony.

Other Considerations Recommendations

G1. DESC should be required to conduct production cost model benchmark studies on an on-going basis, such as once every three years ahead of Comprehensive IRP proceedings, and the Company should discuss benchmarking results in the Stakeholder Working Group.

G2. DESC should evaluate additional ways to incorporate robust risk analyses such as assessing portfolios across multiple planning scenarios. As part of this evaluation, the Company should consider the importance of making near-term decisions that feed into the Company's Action Plan. The Company should discuss this topic in the Stakeholder Working Group.

G3. DESC should update the Commission on the transmission impacts and the natural gas pipeline capacity availability associated with unit retirements and new resource decisions. The Company should file the results of the 2023 TIA Study, including all workpapers and supporting documentation when it becomes available.

A. Initiation of the IRP Process

The Commission first initiated a generic proceeding involving the jurisdictional electric utilities in June 1987 to address least-cost resource procedures based on a comprehensive planning approach.[4] The Commission first required electric utilities to file IRPs in September 1989.[5]

[4] Docket No. 87-223-E, Order No. 87-569, June 18, 1987.
[5] Docket No. 87-223-E, Order No. 89-521, May 17, 1989.

The Commission approved a more formal IRP process in October 1991.[6] The Commission required utilities to file detailed IRPs every three years and file a short-term action plan in the intervening years. In addition to the Commission's IRP procedures, the South Carolina General Assembly passed a bill (Act 449) known as the South Carolina Energy Conservation and Efficiency Act of 1992, adding S.C. Code Ann. § 58-37-40.[7] The definition of an IRP adopted for use in South Carolina is found in S.C. Code Ann. § 58-37-10(2):

> "Integrated resource plan" means a plan which contains the demand and energy forecast for at least a fifteen-year period, contains the supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner, including both demand-side and supply-side options, with a brief description and summary cost-benefit analysis, if available, of each option which was considered, including those not selected, sets forth the supplier's or producer's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service, and describes the external environmental and economic consequences of the plan to the extent practicable. For electrical utilities subject to the jurisdiction of the South Carolina Public Service Commission, this definition must be interpreted in a manner consistent with the integrated resource planning process adopted by the commission. For electric cooperatives subject to the regulations of the Rural Electrification Administration, this definition must be interpreted in a manner consistent with any integrated resource planning process prescribed by Rural Electrification Administration regulations.

Until 1998, utilities followed the IRP requirements established by the Commission's 1991 order. On February 3, 1998, Duke Energy filed a petition to modify the IRP requirements, which led the Commission to re-evaluate IRP procedures.[8] On July 2, 1998, the Commission issued Order No. 98-502, which established a simplified set of IRP requirements based on what the Commission observed at the time to be "the changing nature and deemphasis of Integrated Resource Planning."[9] More recently, the General Assembly passed Act 62, also known as the Energy Freedom Act of 2019, which

[6] Docket No. 87-223-E, Order No. 91-885, October 21, 1991. Attachment A to the Order contained the detailed IRP requirements. Another Order granting clarification and modification was issued on November 6, 1991 (Order No. 91-1002).
[7] www.scstatehouse.gov/billsearch.php?billnumbers=1273&session=109&summary=B.
[8] Docket No. 87-223-E, Order No. 98-502.
[9] *Id.*

addressed many issues associated with utility planning, including updating and re-emphasizing IRP requirements.[10]

B. Act 62 Statute

Act 62 updated Section 40 by changing some requirements and adding others that affected not only the electric utilities, but also the Commission, ORS, and the State Energy Office ("SEO").

Section 40 now requires electric utilities to file IRPs that provide more detailed information to the Commission and other parties, and to post the IRPs on both the Commission's and the utilities' websites. Electric utilities are required to file comprehensive IRPs at least every three years, and to file annual updates with specific information requirements in the intervening years.[11] Section 40(B)(1) sets forth the required information and Section 40(B)(2) sets forth additional optional information.

Section 40 now requires the Commission to establish a proceeding to review each electric utility's comprehensive IRP. Interested parties are permitted to intervene and submit discovery. Section 40(C)(1) states the new requirements are intended to allow interested parties to obtain "evidence concerning the integrated resource plan, including the reasonableness and prudence of the plan and alternatives to the plan …."

Sections 40(C)(1) and (C)(2) state the Commission shall issue a final order within 300 days that approves the utility's IRP as is, if the Commission "determines that the proposed integrated resource plan represents the most reasonable and prudent means of meeting the electrical utility's . . . energy and capacity needs as of the time the plan is reviewed." However, if the Commission finds that the IRP does not meet that standard, then the Commission is required to either order the utility to make specific modifications to the IRP or reject the IRP entirely. If the Commission makes one of these two determinations, Section 40(C)(3) provides procedures and a timeline that requires the utility to submit a revised IRP and ORS to review the revisions and report the findings to the Commission. Then, the Commission "at its discretion may determine whether to accept the revised integrated resource plan or to mandate further remedies that the [C]ommission deems appropriate."

Section 40(C)(2) directs the Commission to consider seven factors as it evaluates whether the IRP is "the most reasonable and prudent means of meeting energy and capacity needs," and determine whether the IRP should be accepted, modified, or

[10] Act 62 became effective on May 16, 2019.
[11] S.C. Code Ann. § 58-37-40(D)(1).

rejected. Act 62 also states that any resource plan accepted by the Commission "shall not be determinative of the reasonableness or prudence of the acquisition or construction of any resource or the making of any expenditure."[12] It further states that the utility retains the burden to prove in a future cost recovery proceeding that any investment and expenditure it makes is reasonable and prudent.

The procedure for reviewing annual updates filed in the two intervening years is different than for the comprehensive filing that utilities must make every three years. For the annual updates, ORS is required to review the utility's filing and submit a report to the Commission containing any recommendations concerning the reasonableness of the annual update. The Commission then must decide if it will "accept the annual update or direct the electrical utility . . . to make changes to the annual update that the commission determines to be in the public interest."[13]

C. DESC's Prior IRP Proceedings

DESC's 2020 IRP

DESC filed the first comprehensive IRP ("2020 IRP") in Docket No. 2019-226-E on February 28, 2020. The Company identified Resource Plan 2 ("RP2") as the preferred least-cost plan,[14] which assumed there would be no early retirements of existing resources and no new resource additions before 2035, including new solar resources beyond the additions in 2020 and 2021 that were already under contract. RP2 further assumed the new resource additions from 2035 and beyond would be natural gas-fired CTs.

In Order No. 2020-832, the Commission rejected DESC's 2020 IRP, required a Modified IRP to be filed, and explained, "the Commission does not believe that DESC's IRP represented the most reasonable and prudent means for DESC to meet its energy and capacity needs."[15] In Order No. 2020-832, the Commission also provided guidance on the Commission's interpretation and expectations for all utilities for compliance with Act 62.

DESC's Modified 2020 IRP

The Company filed the Modified 2020 IRP on February 19, 2021, which utilized new resource cost assumptions and other requirements that were included in Order No. 2020-

[12] S.C. Code Ann. § 58-37-40(C)(4).
[13] S.C. Code Ann. § 58-37-40(D)(2).
[14] Direct Testimony of Eric Bell, Docket No. 2019-226-E, June 4, 2020, p.25, l. 20.
[15] Order No. 2020-832, Docket No. 2019-226-E,December 23, 2020.

832. In the Modified IRP, DESC selected RP8 as the Preferred Plan, based on using revised input assumptions and evaluating eight specific metrics representing cost effectiveness, carbon reduction, renewable generation, fuel price resiliency, reliability, supply diversity, and risk analysis.[16] RP8 assumed the retirement of DESC's Wateree and Williams coal units in 2028, and added new solar and battery storage, CTs, and CC units to meet capacity needs. The Company also indicated that the "expected case scenario" would include the high DSM Case, $12/ton CO_2, and low natural gas price assumptions.

On June 18, 2021, the Commission issued Order No. 2021-429 and accepted DESC's Modified IRP, but included additional instructions for future IRPs and IRP Updates.[17]

DESC's 2021 IRP Update

The Company filed the 2021 IRP Update on August 17, 2021, which affirmed RP8 as the Preferred Plan, and which assumed the Williams and Wateree coal units would be retired by 2028. On July 28, 2022, the Commission issued a directive approving DESC's 2021 IRP Update and reminded the Company that when the 2020 IRP was approved, the Commission issued additional instructions for DESC to address in future IRP Updates and the 2023 Comprehensive IRP. The Commission formally accepted the 2021 IRP Update on October 26, 2022.[18]

DESC's Coal Plants Retirement Study

Commission Order No. 2020-832 required the Company to conduct a Coal Retirement Study, and the Commission issued Order No. 2021-418 on June 9, 2021 to open Docket No. 2021-192-E. On April 28, 2022, the Commission issued Order No. 2022-305 to clarify that the Coal Retirement Study "is not a docket for making decisions regarding the retirement of coal plants," and it issued a modified schedule to allow intervenors to file two rounds of comments. The Company filed the Coal Retirement Report on May 16, 2022, and comments from interested parties were filed by August 1, 2022. ORS filed comments on June 27, 2022, and the Company filed responsive comments on July 15, 2022. No hearings were held, and no order was issued by the Commission.

DESC's 2022 IRP Update

The Company filed the 2022 IRP Update on September 19, 2022. Pursuant to Commission Order No. 2020-832, DESC used the PLEXOS resource optimization model

[16] Modified 2020 IRP, p.48.
[17] Order No. 2021-429, Docket No. 2019-226-E, June 18, 2021.
[18] Order No. 2022-713, Docket No. 2021-9-E, October 26, 2022.

for the first time in the 2022 IRP Update. Based on the analysis performed, DESC identified a new Preferred Plan similar to RP8, but the Company no longer considered it feasible to retire both Wateree and Williams by 2028. The Company referred to the new Preferred Plan as the Williams 2030 Reference Build Plan, in which it found it could still retire Wateree by 2028 but determined Williams could not be retired before 2030. The Company noted that if it did not spend money on ELG upgrades at Wateree, it would have to shut down Wateree by 2028, and it would have to acquire replacement capacity by 2028. Even though the Company recognized there would be risks in acquiring the replacement capacity, the Company stated, “That risk is reasonable given the costs involved.”[19].

In recognition that the Company would be filing the 2023 IRP on January 27, 2023, an accelerated schedule was adopted for the 2022 IRP Update. ORS’s report on DESC’s 2022 IRP Update (“ORS’s 2022 IRP Update Report”) was filed on December 19, 2022, and all rounds of comments were completed by February 20, 2023. In ORS’s 2022 IRP Update Report, ORS included eleven (11) recommendations for the Company to address in the 2023 Comprehensive IRP filing. The Commission adopted all of ORS’s recommendations in Order No. 2023-289, as listed on page two of ORS’s 2022 IRP Update Report.[20]

[19] DESC 2022 IRP Report, September 19, 2022, p. 23.
[20] https://dms.psc.sc.gov/Attachments/Matter/87ebfc52-2d92-417d-a172-ba84ce7c6f05.

II. Compliance with Section 40 and Prior Commission Orders

A. Compliance with Section 40 Requirements

This section first addresses the Company's compliance with the specific requirements listed in Section 40 (Paragraphs (B)(1) and (B)(2)), and then addresses the seven factors set forth in Section (C)(2) that the Commission is directed to consider in deciding whether the Company's "proposed integrated resource plan represents the most reasonable and prudent means of meeting the electrical utility's . . . energy and capacity needs as of the time the plan is reviewed."

Statutory Requirements in Section 40(B)

The following section of the ORS Report provides ORS's assessment of the Company's compliance with Section 40(B)(1) and (2) statutory requirements.

B: An integrated resource plan shall include:

(1)(a): a long-term forecast of the utility's sales and peak demand under various reasonable scenarios.

The 2023 IRP complied with the requirement to provide a long-term forecast of sales and peak demand, and to provide such forecasts under various reasonable scenarios. The load forecast development process is discussed in the Modeling Inputs and Assumptions section at page 45 of the Company's 2023 IRP report.

(1)(b): the type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios.

The 2023 IRP complied with this requirement and provided generation technology assumption information for the generic resources in Table 13 of the 2023 IRP Report. The potential resources include three types of CC units, three types of CT units, off-shore wind ("OSW"), a small modular nuclear reactor ("SMR"), solar resources (both PPA and utility-owned), and battery storage resources. In addition to these supply-side resources, the Company modeled two generic demand response resources.

(1)(c): projected energy purchased or produced by the utility from a renewable energy resource.

The 2023 IRP complied with this requirement and provided energy from renewable generation summed over five year periods in Appendix G of the 2023 IRP Report.

(1)(d): a summary of the electrical transmission investments planned by the utility.

The 2023 IRP complied with this requirement and provided Appendix D entitled, Report on On-going, Completed, Deferred, and Cancelled Transmission Projects.

(1)(e): several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following:

i. customer energy efficiency and demand response programs;

ii. facility retirement assumptions; and

iii. sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks.

The 2023 IRP complied with this requirement and included fourteen (14) different optimized Build Plans with different Market Scenarios. The Market Scenarios considered different assumptions about CO_2, DSM, fuel costs, load forecasts, and coal retirement assumptions. Considering sensitivity cases, in total, the Company studied twenty-four (24) Cases, which were designed to evaluate a wide range of modeling assumptions.

(1)(f): data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio.

The 2023 IRP complied with this requirement and provided information regarding the current generation portfolio in Table 10 on page 36 of the 2023 IRP Report. The Company described licensing activities on page 38 in the Hydroelectric Power Operating Report.

(1)(g): plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan.

The 2023 IRP complied with this requirement to provide Levelized Net Present Value ("LNPV") cost estimates for each of the twenty-four (24) resource plans that were evaluated in tables in the IRP Report (Tables 22, 40, 43, 45. 56) and in Appendix J. In addition, the Company provided excel spreadsheets that demonstrated how the LNPV values were derived.

(1)(h): an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs.

The 2023 IRP complied with the requirements to provide both cost and reliability impacts. Regarding cost impacts, the Company performed PLEXOS optimization analyses to find the lowest cost expansion plans under different modeling assumptions, including numerous sensitivity analyses. In addition to presenting LNPV results, the Company also provided retail bill impacts for each of the twenty-four (24) cases that were evaluated. Appendix H includes Residential Bill Impacts for a hypothetical 1,000 kilowatt-hour ("kWh") per month residential customer for each of the cases.

The Company evaluated reliability impacts in several ways. First, DESC contracted with Astrapé to perform a detailed resource adequacy and reliability study, which determined the appropriate planning reserve margin target for the Company. Astrapé provided a report entitled DESC 2023 Planning Reserve Margin Study on January 27, 2023, and the results of the Astrapé analysis were factored into DESC's 2023 IRP. In addition to determining a Target Reserve Margin, Astrapé also derived Effective Load Carrying Capability ("ELCC") results associated with solar, pumped storage and battery storage technologies that were also factored into DESC's IRP study results. On top of the reliability modeling assumptions, the Company stated that in developing resource plans, PLEXOS ensures that "No plans are formulated to provide more resources or less resources than are necessary to meet the system reliability criteria," which was established as part of the Astrapé study.[21]

The Company performed additional reliability assessments of the expansion plans to consider whether the generation resources in the plans contain desirable reliability characteristics. The characteristics the Company evaluated include Black Start, Fast Start, Geographic Diversity, and Proximity to Load. The Company assigned a score for each resource in the different Build Plans and came up with a Reliability Ranking that was used in comparing the resource plans.

(1)(i): a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.

[21] 2023 IRP, p. 68.

The 2023 IRP complied with the requirement to provide a forecast of peak demand and provided details regarding the amount of peak demand reduction the Company expects to achieve. The Company's load forecast is discussed in the Modeling Inputs and Assumptions section of the 2023 IRP Report at page 45. The Company described the winter and summer peak demand forecasts separately and discussed drivers that led to differences in the load forecasts compared to the 2022 IRP Update. The Company also described the approach used to develop the high and low demand forecasts in addition to the reference demand forecast. The Company studied the impacts of achieving greater levels of electrification, energy conservation, and demand response. Regarding energy conservation and demand response, the Company engaged ICF to perform the new 2023 DSM Market Potential Study ("MPS"). The Company stated that as part of the study, "ICF also completed a comprehensive evaluation of Demand Response ("DR") programs for both residential and commercial customers with an emphasis on decreasing the winter peak."[22]

(B)(2): An integrated resource plan may include distribution resource plans or integrated system operations plans.

The Company addressed this optional requirement and described the status of the rollout of DESC's Automated Metering Infrastructure ("AMI") project, which will provide a direct two-way wireless connection between the Company and the customer's meter, which will allow the Company to introduce more demand response programs.

Statutory Requirements in Section 40(C)(2)

The statute directs the Commission to consider seven factors to determine whether the IRP "represents the most reasonable and prudent means of meeting the electrical utility's . . . energy and capacity needs at of the time the plan is reviewed." The following are the factors that must be considered:

C(2): The Commission, in its discretion, shall consider whether the plan appropriately balances the following factors:

(a) resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins.

(b) consumer affordability and least cost.

(c) compliance with applicable state and federal environmental regulations.

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[22] *Id.* at 16.

(d) power supply reliability.

(e) commodity price risks.

(f) diversity of generation supply.

(g) other foreseeable conditions that the Commission determines to be for the public's interest.

The Commission is required to consider these seven factors in the evaluation of whether DESC's IRP "represents the most reasonable and prudent" means of meeting its capacity and energy requirements, and in doing so the Commission is permitted to use discretion to judge the factors that could receive a greater decision-making weighting compared to the other factors.

As mentioned previously, the Commission issued guidance on the interpretation and expectations for compliance with the statute in Order No. 2020-832. The guidance discussed the standard a utility's IRP must meet and the factors the Commission will use to evaluate a utility's IRP, as follows:

1. Reasonable – "the plan must be 'reasonable,' meaning it is rational, logically consistent, and the result of sound judgment. In the context here, this requires consideration of whether the utility's plan meets the requirements of Act 62 and comports with industry norms and widely-known IRP best practices."

2. Prudent – "it gives due consideration to actual and foreseeable future conditions and risks. Such consideration should take into account the relative costs and benefits of avoiding potential future risks, such as regulatory, capital, or fuel risks."

3. Detailed Information – "the IRP and the record must provide sufficient information about each of the seven balancing factors to enable the Commission to determine if the IRP appropriately balances each of them. Act 62 also requires that the plan must represent the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed."

4. Best Available Tools and Modeling Capabilities – "This is a significant standard that implies that IRP requirements should not be static, but rather should continuously improve over time as standards and practices improve and evolve. It also implies that a utility may not do the bare minimum, but rather must ensure that its IRP is the result of serious planning and consideration using the best available data and tools available to it."

5. Risk – "Act 62 requires that the Commission balance a number of factors, including "commodity price risks" and "diversity of generation supply."

This Report evaluates the Company's data assumptions, modeling approaches, and ultimately reaches a conclusion regarding the reasonableness of DESC's Preferred Plan. To that end, the Commission "[e]mphasizes that although cost is an important consideration, 'reasonableness' and 'prudence' do not require that the utility simply select the least-cost resource plan, given the inherent uncertainty of sensitivity assumptions for future conditions."[23]

DESC evaluated fourteen (14) Build Plan portfolios that were tested across various Market Scenarios that resulted in an evaluation of twenty-four (24) total cases designed to consider regulatory, environmental, load, and commodity price risks. The Company relied on results from the previously conducted Coal Retirement Study and performed sensitivity evaluations associated with an alternative Williams retirement date. The Company conducted evaluations of low, reference, and high levels of DSM, which all provided insight on DESC's path forward, the options it could pursue in the future, and whether that path forward provides sufficient flexibility to allow the utility to alter course as conditions change.

In addition to optimization analyses performed in this IRP, DESC conducted numerous additional studies, including an EV Adoption Study, a Reserve Margin Study, a DSM Market Potential Study 2023, the 2022 Coal Plant Retirement Study, and several TIA studies. The key components of DESC's Preferred Plan concern compliance with environmental regulations, retirement of coal units, decisions about replacement resources, the addition of renewable and storage resources, utilization of DSM resources, and consideration of the electrification impacts.

DESC's Preferred Plan indicated that Wateree will be retired in 2028 and Williams in 2030, which would result in an ELG capital investment at Williams but not an investment in ELG upgrades at Wateree. DESC determined that it could take one of two approaches to replace the Wateree capacity: 1) add a 400 megawatt ("MW") battery storage resource at the Wateree site, or 2) add a 262 MW CT along with 100 MWs of battery storage capacity at the Urquhart Station. Of the two options, the Company determined it would be more economic to replace Wateree with a 400 MW battery resource; however, the Company noted there could be issues that would make it more practical to install the 262

[23] Order 2020-832, Docket No. 2019-226-E, p. 13.

MW CT plus 100 MW battery resource instead at just a slightly higher cost (1.25% higher).[24] The Company explained the issues as follows:

> From a schedule perspective, supply chain disruptions and equipment delays could make battery replacement impracticable on a timetable that allows DESC to avoid substantial ELG compliance costs at Wateree. By contrast, CT technology is mature, its costs and construction lead-times are well understood, and its supply chains are stable and well established. [25]

Given the similarity in cost, and the potential issues with the installation of battery resources, the Company proposes to "issue an RFP to further refine cost estimates for replacement resources for Wateree."[26]

With regard to Williams, DESC's Preferred Plan assumes Williams cannot be retired any earlier than 2030. DESC explained this decision by stating:

> Williams is the only large generator on the DESC system in the Charleston area and is critical to providing reliable service to customers there. Electric transmission resources and natural gas supplies are limited in the Charleston area, and the 2022 Coal Plants Retirement Study found it was impracticable to retire and replace Williams before December 31, 2030, at the earliest. [27]

As such, DESC proposed to invest in ELG upgrades required for continued operation of Williams past 2028. DESC's Preferred Plan would replace the Williams unit with a 2x1 CC unit that would be jointly shared with Santee Cooper (the "Shared Resource"). DESC would receive 663 MW of capacity, and the Company states "DESC is likely to pursue the Shared Resource at the Canadys Site."[28]

DESC's Preferred Plan assumed that 1,046 MW of CT capacity, 5,025 MW of solar capacity, and 1,500 MW of battery storage capacity would be added to the System by 2050. The Company's Preferred Plan assumed that DESC would achieve a .51% energy sales reduction due to DSM programs, referred to as the Medium DSM Case. While the Company studied other DSM Cases and maintained that the assumption is reasonable, the Company stated it would be challenging to achieve an energy sales reduction of .51%.

[24] 2023 IRP, p. 73.
[25] *Id.* at 74.
[26] *Id.*at 73.
[27] *Id.* at 7.
[28] DESC response to ORS 1-12b.

DESC performed a reasonable resource planning study that addressed the seven factors that the Commission is required by statute to use to evaluate a utility's resource plan. However, ORS identified several items that DESC should provide a response to in Rebuttal Testimony, as identified in this Report. The Company used detailed information to develop the Preferred Plan using typical industry IRP best practices. For example, the Company's PLEXOS optimization model is widely used by the electric utility industry. Astrapé has performed many studies for electric utilities using the Strategic Energy & Risk Valuation Model ("SERVM") reserve margin modeling tool. Likewise, ICF and Guidehouse are well known consulting firms that frequently perform demand side management (ICF) and electric vehicle studies (Guidehouse) for electric utilities.

DESC's approach to develop a series of Build Plans, and test the plans across a range of Market Scenarios is considered to be a "best practice" in the industry. In addition, the Company properly evaluated risk in analyses that were performed. For example, the Company properly considered the risk of incurring higher fuel costs, the need to address potential environmental regulations that have not yet been implemented, and the impacts that growth in electric vehicles would have on DESC's service territory.

B. Compliance with Prior Commission Orders

ORS reviewed all aspects of DESC's 2023 IRP, which included the 2023 IRP Report, input assumptions, modeling analyses, and results. ORS verified all requirements as prescribed by the Commission for the 2023 IRP in Order Nos. 2020-832 (2020 IRP), 2021-429 (2020 Modified IRP), 2022-713 (2021 IRP Update), and 2023-289 (2022 IRP Update). Order Nos. 2022-713 and 2023-289 required the Company to consider all recommendations of the parties in the IRP Updates and required the Company to continue to engage with stakeholders and address the eleven recommendations raised by ORS in the 2022-9-E Docket as part of the 2023 Comprehensive IRP hearing.

ORS developed Tables A-1, A-2, A-3, and A-4 in Appendix A below to summarize the requirements specified in the prior Commission Orders pertaining to the Company's last Comprehensive and Modified IRP filing (2020 IRP). Each table cross-references the requirements to the corresponding sections of the Commission Orders, including the Order's Findings of Fact, Evidence and Evidentiary Conclusions, and Ordering Paragraphs sections. The specific purposes of Tables A-1 through A-4 in Appendix A are as follows:

Table 1

Table	Purpose
A-1	Requirements identified by Order No. 2020-832.
A-2	Requirements identified by Order No. 2020-832 (issued after the 2020 IRP), but revised by Order No. 2021-429.
A-3	New requirements identified by Order No. 2021-429 (issued after the Modified IRP).
A-4	Requirements identified by Order Nos. 2020-832 and 2021-429 for Stakeholder Engagement.

While the tables in Appendix A include all requirements contained in the Commission Orders, Table 2 lists an item that the Commission specifically required DESC to include in the 2023 IRP. Table 2 cross-references where the requirements are discussed in both DESC's 2023 IRP Report and within this Report. The item in Table 2 is also included in Appendix A.

Table 2

Action Item(s)	Summary of Requirements	DESC 2023 IRP Section	ORS 2023 Report Section
27	In its 2023 IRP, DESC must include a comprehensive evaluation of the cost effectiveness and achievability of higher levels of savings, including savings levels of 1.25%, 1.5%, 1.75% and 2%. As outlined in step 3 of the late-filed exhibit, this comprehensive evaluation must consider substantive additions and modifications to the Company' existing DSM portfolio. In implementing this plan, DESC must work with stakeholders, particularly the Advisory Group, and provide opportunities for iterative review, input, and feedback on the Company's analysis and subsequent portfolio development. As part of this presentation in the 2023 IRP, DESC shall include potential incentive options and best practices to achieve the modeled levels of DSM.	The 2023 DSM Potential Study (p. 14); DSM Assumptions (p. 49); Appendix C	Section C: Energy Efficiency and Demand Side Management

III. Evaluation of DESC's 2023 IRP

A. Reserve Margin

DESC's summer and winter reserve margins are currently 14% and 21%, respectively, based on the Company's analysis presented in the 2020 IRP. While ORS did not object to the use of these summer and winter peak reserve margins for long-term resource planning, ORS expressed concerns regarding the Company's methodology, which was based on a unique approach that included a number of separate components that ORS found to be inconsistent with general electric utility industry practice.

These concerns were extensively discussed in ORS's July 10, 2020 IRP Report, and ORS made a number of recommendations to improve the Company's reserve margin analysis and provide appropriate resource adequacy for the DESC System. Specifically, ORS made the following recommendations:

2.1 The Company should consider utilizing an optimal economic based reserve margin methodology that considers the cost to customers of unserved load and energy compared to the cost of meeting various levels of reliability.

2.2 Company should incorporate a traditional Loss of Load Expectation ("LOLE") analysis and should present the results of a more comprehensive LOLE analysis that includes probability assessments of the impact on peak loads of varying weather conditions, and also considers the impacts of a reasonable amount of tie line support from neighboring utilities.

In the 2023 IRP, DESC performed a resource adequacy analysis that met both of these recommendations. DESC retained Astrapé Consulting to perform a resource adequacy analysis using Astrapé's SERVM model. SERVM utilizes a Monte Carlo simulation methodology to evaluate several key variables that impact resource adequacy. The objective of the analysis is to determine the planning reserve margins for both the summer and winter that will provide for a LOLE of 0.1 days/year or the equivalent of the common industry practice of one loss of load event in 10 years. ORS reviewed Astrapé's resource adequacy analyses in the Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") 2020 IRPs and the analyses were reasonable.

Astrapé's resource adequacy analysis for DESC generally followed the same approach as used by Astrapé in the DEC and DEP analyses. SERVM performs a Monte Carlo simulation of a number of key factors that impact electric utility system reliability. Among these are: random forced outages of DESC's generating resources, weather variation and its impact on loads, and load forecast errors (either too high or too low) due to errors in the forecast of driving economic factors impacting economic activity in the DESC region.

Generally, the standard electric utility modeling of LOLE only reflects the outage probability distribution of the utility's generation resources. The analysis assumed that the system hourly load model is fixed and reflects assumptions about normal weather. In addition to modeling the probabilistic distribution of generator outages or availability, SERVM also simulates variation in the hourly load model based on 42 years of weather history (1980-2021). All of the SERVM calculations are made for a single base year – in the DESC modeling, the base year is 2026. The model uses an hourly load forecast for 2026 that is simulated against each of the 42 weather years. For example, one simulation might utilize weather data for the year 2004 and produce an hourly load shape for use in the LOLE calculation based on that year's weather. SERVM assumes that there is an equal probability of any of the 42 years of weather events could occur. For each of these 42 weather years, the hourly load forecast reflects either a downward or upward adjustment to reflect load forecast error.

As done in the DEC and DEP resource adequacy studies, Astrapé performed two alternative calculations of LOLE. The first calculation assumed that the DESC System was an "island," meaning that there were no interconnections with neighboring utilities. This calculation is not designed to produce a planning reserve margin. Rather, it simply provides a benchmark to assess the benefits and reliance of outside systems to achieve resource adequacy. Based on the "island" analysis, DESC would require a reserve margin of 43.1% in order to meet the industry standard 1 day in 10 year level of reliability. This scenario assumes that DESC cannot rely on any support from neighboring utilities. While there are legitimate questions about the level of tie line support during extreme weather conditions, especially in the winter, it is not realistic to assume no tie support. The standard interconnection/tie support-based analysis conducted by Astrapé found that in order to achieve a 1 day in 10-year level of reliability, DESC requires a winter reserve margin of 20.1%. If DESC provides sufficient capacity in the winter to meet this 20.1% reserve margin, the resulting summer reserve margin would be 23.2%. While a standalone summer reserve margin of 15% would produce a LOLE of 1 day in 10 years, meeting the winter reserve margin results in the summer reserve margin being more than satisfied.

Table 3 below, which is an excerpt of data provided in Table 10 of Astrapé's DESC Resource Adequacy Report, shows the LOLE at a 20% winter reserve margin and a 21% winter reserve margin. As can be seen, the reliability of the System is almost identical at either of these two reserve margins (slightly better than 1 day in 10 years at 21%, very slightly worse than 1 day in 10 years at 20%). It should be noted that these reserve margin/LOLE relationships are based on a polynomial regression consisting of only 5 observations from the SERVM output. Using this regression, the LOLE at exactly 1 day in 10 years would require a 20.3% winter reserve margin.

Table 3
Winter Reserve Margin vs. LOLE

Winter Reserve Margin(%)	Summer Reserve Margin(%)	LOLE (events per year)	Outage Days in 10 Years
5.0%	7.9%	0.310	3.10
6.0%	8.9%	0.293	2.93
7.0%	9.9%	0.277	2.77
8.0%	10.9%	0.261	2.61
9.0%	12.0%	0.245	2.45
10.0%	13.0%	0.230	2.30
11.0%	14.0%	0.215	2.15
12.0%	15.0%	0.200	2.00
13.0%	16.1%	0.187	1.87
14.0%	17.1%	0.173	1.73
15.0%	18.1%	0.160	1.60
16.0%	19.1%	0.148	1.48
17.0%	20.2%	0.136	1.36
18.0%	21.2%	0.124	1.24
19.0%	22.2%	0.113	1.13
20.0%	23.2%	0.103	1.03
21.0%	24.3%	0.093	0.93
22.0%	25.3%	0.083	0.83
23.0%	26.3%	0.074	0.74
24.0%	27.3%	0.065	0.65
25.0%	28.4%	0.057	0.57
26.0%	29.4%	0.049	0.49

Reserve Margin Analysis Assessment

Overall, the Company’s 2023 resource adequacy analysis is reasonable and represents an improvement compared to the analysis that was performed in the 2020 IRP. The most significant issue that ORS identified concerns the modeling of extreme weather. As noted in the Astrapé analysis, in order to perform a full 42 year weather simulation, it was necessary to develop a load/weather model that related weather metrics, such as temperature to load. The relationship between load and weather has evolved significantly over 42 years as weather sensitive energy usage has changed due to different, and more efficient appliances, weatherization, and other factors. Since the ultimate objective of the SERVM analysis is to predict hourly load in 2026 under different weather conditions, but reflect the same underlying customer end uses (and their efficiency levels), the load/weather model must be developed using a relatively short, recent set of weather and load data. In addition, Astrapé has imposed a restriction that sets the average peak load from the simulations for the most recent 30 years (1992-2021) equal to the Company's weather normalized peak demand forecast for 2026. However, the "training period" used to develop the load/weather model relationships (2017-2021) does not contain the mix of extreme temperatures found in the full weather data base. To put this in simpler form, the weather data that is used to estimate the load/weather model represents a different distribution of weather than has occurred during the past 42 years (and likely, the past 30 years). This means that the model may not accurately measure the impact on 2026 loads if, for example, 1985 weather is simulated in the SERVM analysis. This is a particularly significant problem during extreme winter weather conditions.

Astrapé included an analysis that illustrates why capturing the impact of extreme weather is important (see Table 11 in Astrapé's Report). From that table, 59% of the weighted average LOLE for all 42 years of weather is determined by the weather in just three years (1982, 1983 and 1985). Over 85% of the LOLE is accounted for five additional weather years (1981, 1986, 1996, 2003 and 2015) are added into the average. This means that these eight weather years are the years that primarily drive the overall LOLE. None of these weather years are included in the load/weather model development that is used to convert each of the 42 weather years into a simulated 2026 load curve.

Astrapé attempted to address extreme weather conditions, as it developed separate extreme load/weather statistical regression models. While the Astrapé methodology to address extreme weather conditions, or some variant of it, is required in order to perform the full 42-year load/weather simulation, additional evaluation of this methodology should be considered in future IRPs.

Finally, the Astrapé resource adequacy analysis also developed estimates of solar and battery energy storage systems ("BESS") ELCC. The analysis, which relies on the same SERVM database and model, is designed to measure the summer and winter capacity value of renewable resources, such as solar, for use in long term planning. The ELCC for a specific resource is in the form of a percentage factor that can be applied to the nameplate capacity of the resource. As in prior DESC analyses of the value of solar generation during the critical winter peak period, the Astrapé ELCC analysis showed a very small winter peak capacity value for various penetrations of solar generation. The ELCCs range from 2.7% to 0.5% for incremental solar capacity of 100 MW up to 1,650 MW. Due to the timing of the DESC winter peak (early morning), the capacity value of solar is very low.[29]

Reserve Margin Recommendations

A1. DESC should fully document the extreme winter weather statistical analyses, and demonstrate that the models reasonably reflect winter loads during extreme low temperatures in future IRPs. The Company should also report on the Company's findings in the Stakeholder Working Group.

B. Energy and Demand Forecast

The Company's load forecast is discussed in the Modeling Inputs and Assumptions section of the 2023 IRP Report at page 45. In ORS's review of the Company's 2020 IRP load forecasts (Review of Dominion Energy South Carolina, Inc. 2020 Integrated Resource Plan, Docket No. 2019-226-E, South Carolina Office of Regulatory Staff, July 10, 2020), ORS confirmed that both the energy and peak demand forecasts were reasonable. In the 2023 IRP, the general load forecasting methods the Company used were essentially identical to those used in the 2020 IRP; however, the current load forecasting models were updated with more recent data.

Load Forecast Methodology

Following the 2020 approach, DESC's 2023 forecast is based on a 24-month short-term forecast and a separate long-term forecast covering an additional 18 years (20 years total). For the 2023 IRP analysis, the forecast covers the period 2023-2037.

Table 4 below summarizes the 2023 forecast (annual energy, and summer and winter peak demand). Energy sales are projected to grow at 0.9% per year, while the winter peak load is projected to grow at 0.6% annually. Even though DESC's summer peak is higher than the winter peak, for purposes of meeting reliability requirements and satisfying resource requirements, addressing DESC's capacity need at the time of the winter peak will automatically result in DESC's summer capacity need being met.

As discussed in DESC witness Perricelli's testimony, the summer peak is actually growing at a higher rate than the winter peak due to the expected addition of significant EV customer adoption. Because EV charging typically takes place in late afternoons or

[29] This is consistent with analyses that the ORS has reviewed for other South Atlantic region electric utilities, such as Georgia Power Company, Duke Energy Carolinas and Duke Energy Progress.

evenings, it impacts the summer peak to a much greater extent than the winter peak. The DESC winter peak occurs in the early morning hours, and therefore there is less of a load addition due to EV usage in the winter months. For example, in 2037, the EV load addition in the summer is projected to be 358 MW, while in the winter the additional load is only 99 MW.

Table 4

DESC 2023 IRP Load and Energy Forecast

		Peak Forecast	
Year	Sales GWh	Summer MW	Winter MW
2023	23,941	4921	4902
2024	23,247	4791	4775
2025	23,361	4825	4813
2026	23,572	4867	4851
2027	23,789	4915	4891
2028	24,018	4966	4931
2029	24,288	5021	4971
2030	24,584	5079	5009
2031	24,890	5142	5048
2032	25,249	5210	5091
2033	25,614	5281	5133
2034	25,988	5356	5179
2035	26,370	5433	5228
2036	26,739	5509	5274
2037	27,157	5595	5332
CAGR	0.90%	0.91%	0.58%

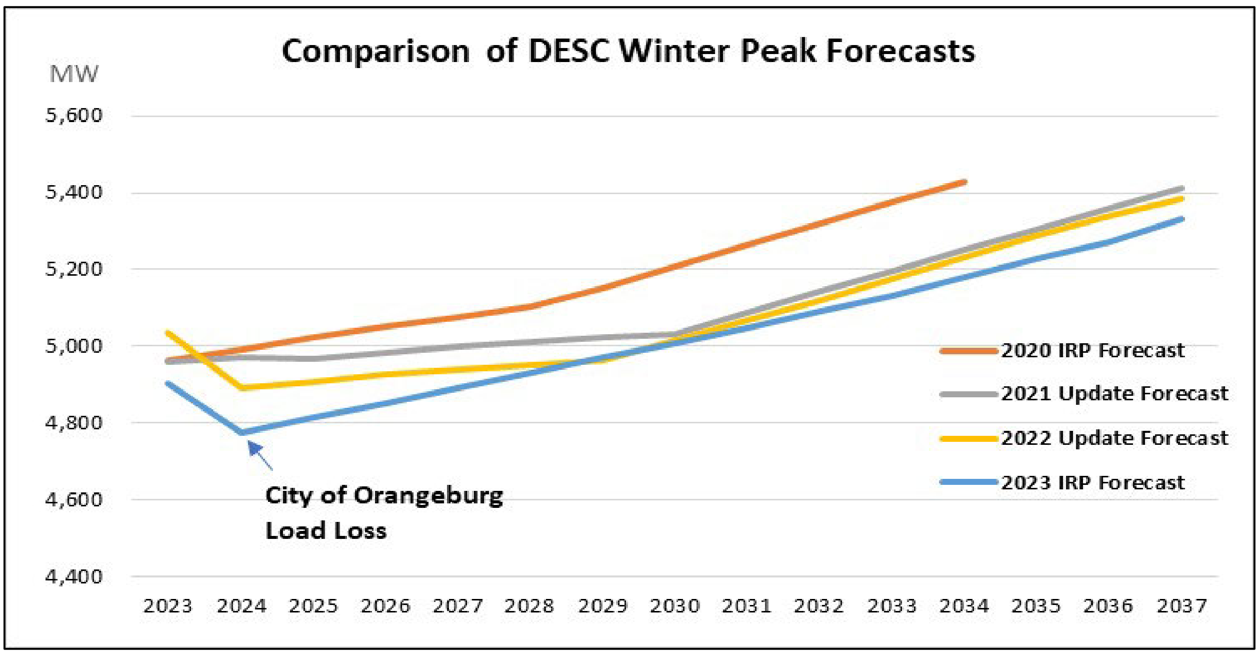
Table 5 below shows a comparison of the 2023 winter peak demand forecast to both the original 2020 IRP forecast and the 2021 and 2022 Update forecasts. The 2023 forecast is generally consistent with recent DESC winter peak projections, after accounting for the loss of the City of Orangeburg load beginning January 1, 2024.

Table 5: Comparison of DESC Winter Peak Forecasts (MW)

	2020 IRP Forecast	2021 Update Forecast	2022 Update Forecast	2023 IRP Forecast
2023	4,964	4961	5035	4902
2024	4,992	4973	4893	4775
2025	5,022	4967	4907	4813
2026	5,051	4984	4926	4851
2027	5,077	4998	4939	4891
2028	5,102	5013	4953	4931
2029	5,152	5024	4964	4971
2030	5,209	5031	5016	5009
2031	5,266	5086	5067	5048
2032	5,319	5143	5121	5091
2033	5,375	5197	5176	5133
2034	5,428	5252	5232	5179
2035		5306	5287	5228
2036		5360	5339	5274
2037		5411	5386	5332

Figure 1 shows a graphical comparison of these recent winter peak forecasts.

Figure 1



Assessment of the DESC Load and Energy Forecasts

The Company has continued using the forecasting methodology that was previously presented in the 2020 IRP and evaluated by ORS in the July 10, 2020 report. In the 2020 evaluation, ORS expressed concerns with the DESC forecasts and recommended the concerns be addressed in a future IRP, yet the 2023 IRP forecast methodology remains generally the same. The most critical of the ORS concerns is with the Company's peak demand forecast methodology. Specifically, for the residential and commercial rate classes, which comprise about 84% of the DESC winter peak load in 2024, the Company developed a weather normalized peak load per customer based on residential and commercial class load research data, and then multiplied that by the number of projected residential and commercial customers. The DESC analysis in the 2020 IRP assumed a constant kW demand per customer over the entire 20-year forecast horizon and did not incorporate any of the usual factors that are assumed to impact MWh energy usage for the residential and commercial classes, such as changes in electric price, appliance saturation, building efficiency, or economic activity are being incorporated into the average customer profile.

In the 2023 forecast, to account for the usual factors assumed to impact MWh energy usage for residential and commercial classes, the Company applied adjustments to the residential and commercial peak load forecasts that are designed to reflect changes in average kW demand per customer. These adjustments are summarized in Company Witness Perricelli's testimony in Table 4 (page 10). For the Residential class, the adjustments include: EV load, SEER changes, Lighting efficiency changes, water heating efficiency changes, other energy efficiency and net metering. For the Commercial class, the adjustments include EV, lighting, energy efficiency and net metering.

To put the Company's peak load adjustments into perspective, Table 6 shows these Residential and Commercial adjustments on a per customer basis, consistent with the methodology used by the Company to produce the forecasts. The adjustments by the Company are insignificant, as the adjustments amount to less than 0.005% of the Residential class average kW per customer forecast and about 0.001% of the Commercial class average kW per customer forecast. As such, the Residential and Commercial peak demand forecasts (winter and summer) are based almost exclusively on the growth rate of the number of Residential and Commercial customers.

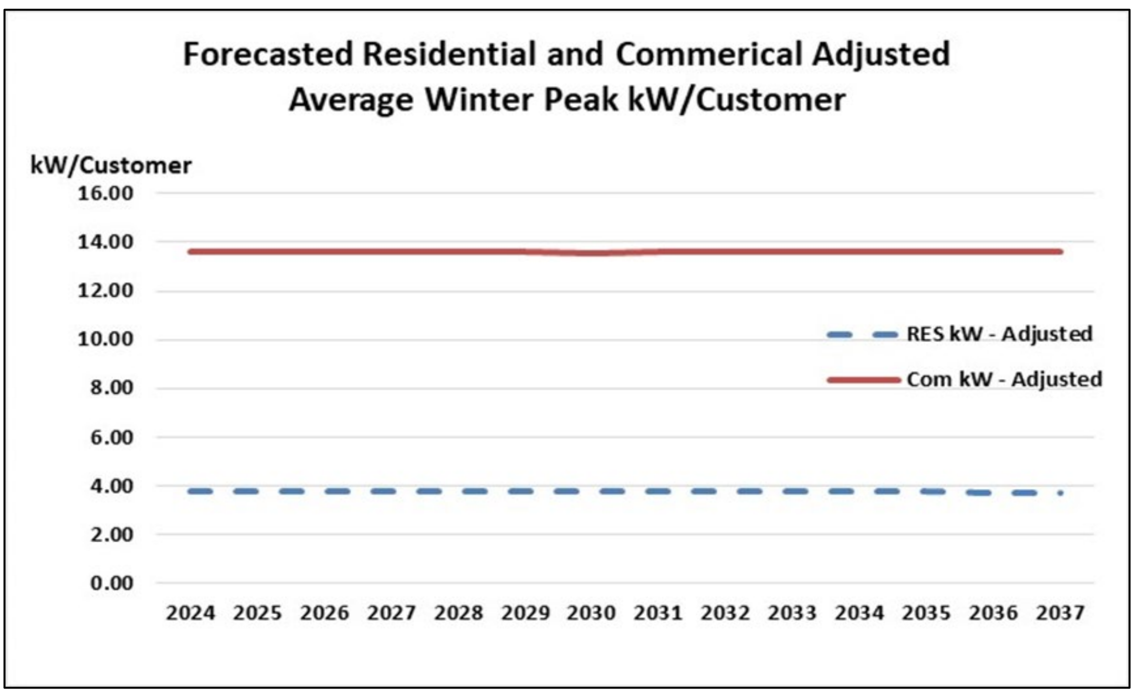
Table 6

Impact of Residential and Commercial Class "Adjustments" to Winter Peak Load Forecast

Year	Residential Winter Peak Load/Customer (kW)	Residential Adjustment Per Customer (kW)	Percent	Commercial Winter Peak Load/Customer (kW)	Commercial Adjustment Per Customer (kW)	Percent
2024	3.77	-0.000026	-0.00069%	13.60	-0.000068	-0.00050%
2025	3.77	-0.000040	-0.00107%	13.60	-0.000096	-0.00071%
2026	3.77	-0.000055	-0.00147%	13.60	-0.000114	-0.00084%
2027	3.77	-0.000067	-0.00179%	13.60	-0.000141	-0.00104%
2028	3.77	-0.000079	-0.00210%	13.60	-0.000159	-0.00117%
2029	3.77	-0.000092	-0.00244%	13.60	-0.000167	-0.00123%
2030	3.77	-0.000103	-0.00273%	13.60	-0.000174	-0.00128%
2031	3.77	-0.000114	-0.00302%	13.60	-0.000164	-0.00121%
2032	3.77	-0.000123	-0.00327%	13.60	-0.000135	-0.00100%
2033	3.77	-0.000134	-0.00355%	13.60	-0.000107	-0.00079%
2034	3.77	-0.000143	-0.00379%	13.60	-0.000062	-0.00046%
2035	3.77	-0.000153	-0.00406%	13.60	0.000000	0.00000%
2036	3.77	-0.000161	-0.00428%	13.60	0.000052	0.00039%
2037	3.77	-0.000161	-0.00427%	13.60	0.000147	0.00108%

Figure 2 is a chart of the Company's forecasted, adjusted residential and commercial average winter peak kW per customer for the period 2023 through 2037, based on the data from Table 6.

Figure 2



The figure indicates there is essentially no change in the average winter peak kW per customer during the entire forecast period. At the same time, the Company projected changes in residential and commercial average kWh use per customer during this same period. Based on the energy forecast results presented in Company Witness Perricelli's Tables 1 and 2, Residential Class average use per customer in 2037 is projected to be 13,116 kWh, compared to 2023 average residential use of 12,501 kWh per customer. This reflects a cumulative growth rate of 4.9% in average use during the period. For the commercial class, a similar calculation produces a cumulative growth rate in average kWh/customer usage of 5% during the period. The cumulative growth rate in the residential class and commercial class winter peak kW/customer are 0% and 0% respectively, even after accounting for adjustments for energy efficiency and EV. Table 7 below summarizes this comparison.

Table 7

Comparison of Growth in Average Winter Peak/Customer vs. Average kWh/Customer 2023-2037

	Residential		Commercial	
	Winter Peak kW	Average kWh	Winter Peak kW	Average kWh
2023	3.77	12501	13.60	71364
2037	3.77	13116	13.60	74922
Cumulative Change	0.00%	4.92%	0.00%	4.99%

For the industrial class, which comprises about 14.5% of winter peak load in 2024, the Company uses the industrial class energy forecast (average MW demand/hour), adjusted for the industrial class ratio of peak demand to average demand. In this manner, the economic factors that impact the energy forecast are directly incorporated into the peak load forecast.

High And Low Forecast Methodology

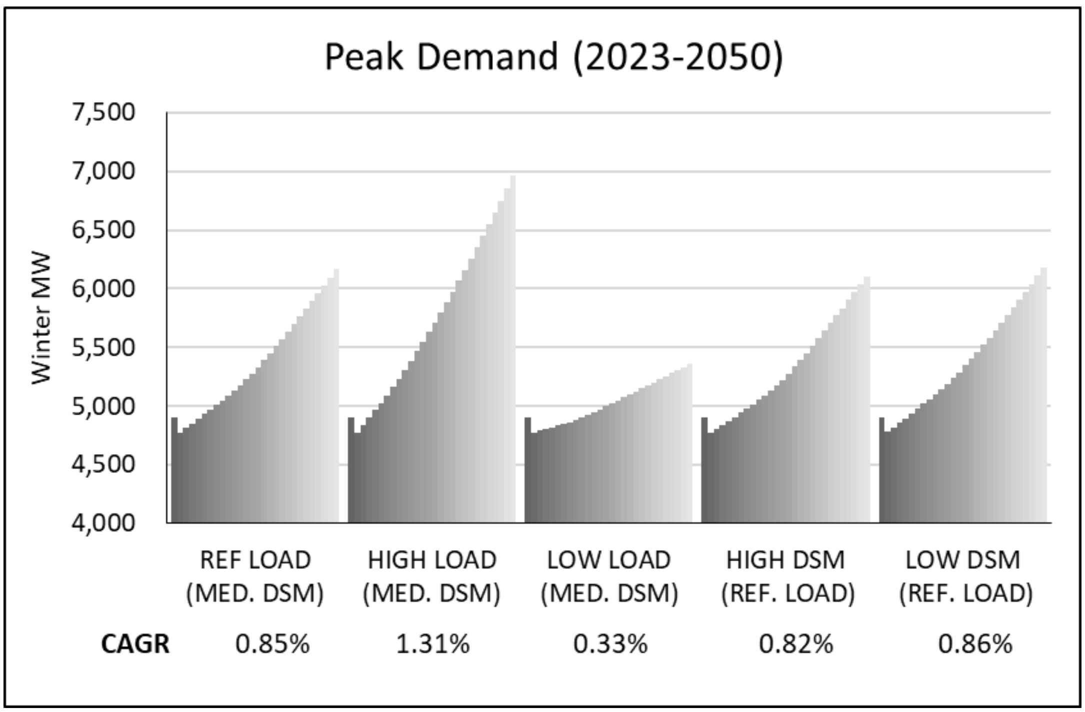
The Company complied with S.C Code Ann. § 58-37-40(B)(1)(a), which requires sensitivity analyses of load growth, by simply setting the "high" forecast scenario equal to the average annual growth rate of the base peak load forecast plus 0.5% per year. For the low load forecast, the Company reduced the average annual Base Case growth rate by 0.5%. The Company's approach is different than the approach used by other utilities that use econometric models and include alternative economic activity assumptions (e.g., higher or lower real per capita income growth) in their sensitivity cases. DESC's approach to the sensitivity forecasts is not unreasonable; however, the approach used by the

Company does not directly address the relationship of load and economic growth levels in the DESC service area, in the same way that a more rigorous econometric study would. ORS recommends that the Company perform more detailed analyses to assess the reasonableness of its Residential and Commercial class peak load forecasts in future IRPs, with particular attention on providing support for the assumption that average peak load per residential and commercial customer will remain essentially constant over the forecast horizon.

Sensitivities for Expansion Planning

In addition to the Base Case, Low, and High growth rate scenarios, the Company also evaluated high and low DSM scenarios. The evaluation produced four alternative load growth scenarios, in addition to the Base Case forecast that the Company used in PLEXOS modeling. In total, DESC provides 5 unique load profiles for Market Scenario development as shown in Figure 3.

Figure 3: Winter Peak Load by Market Scenario



The DSM sensitivities are small adjustments to the reference load forecast reflecting the market potential study as described below.

Electric Vehicle Forecast

The Company explained that changes in the customer load forecast, energy efficiency, and EV adoption were significant drivers that led to differences in the load forecast compared to the 2022 IRP Update. EV adoption especially impacted the Company's load forecast. Company Witnesses Perricelli and Robinson presented testimony that supported the Company's load forecast and EV assumptions. Witness Perricelli described the impact of EV adoption to the forecast:

> Guidehouse determined that EV adoption will have its greatest impact on summer peak load because EV owners are expected to be charging their vehicles at the end of the day when summer peaks occur. In contrast, the winter peaks happen in the early morning hours after most EV charging will be complete, so EV contribution to winter coincident peak is reduced. In 2037, the estimated contribution to summer peak from EV charging is approximately 358 MW or 6.4% of peak summer demand. [30]

As mentioned above, because of reliability impacts, DESC's reserve margin requirement is influenced more by the winter peak demand than the summer peak demand, and the large adoption of EVs has less impact on the winter peak than it does on the summer peak, due to when the peak occurs and when customers typically charge EVs. However, EVs affected the winter peak.

DESC's assumptions regarding the adoption of EVs represent an increase from the 2022 IRP Update. In the 2022 IRP Update, the Winter EV load impact was expected to grow from 1 MW in 2023 to 30 MW in 2037, whereas in the 2023 IRP, the EV load is expected to grow from 1 MW to 99 MW over the same period.[31] Given that EV usage is in the early stage of adoption, there appears to be an opportunity to address this forecasted load growth proactively. As DESC continues to monitor the EV impact on its load, ORS recommends DESC provide details on the EV rate designs and load management programs the Company considers to mitigate EV impacts on peak demand and capacity need in Rebuttal Testimony

<u>Energy and Demand Forecast Recommendations</u>

B1. DESC should perform more detailed analyses to assess the reasonableness of its Residential and Commercial class peak load forecasts in future IRPs, and in particular, the Company should provide support for the assumption that the average peak load per

[30] Direct Testimony of Bradley T. Perricelli, Docket No. 2023-9-E, p. 21, ll. 1-7.
[31] DESC response to ORS AIR 1-57.

residential and commercial customer will remain essentially constant over the forecast horizon.

B2. DESC should provide details in Rebuttal Testimony on the EV rate designs and load management programs the Company considers to mitigate EV impacts on peak demand and capacity need.

C. Energy Efficiency and Demand Side Management

In the 2020 IRP, the Commission found the Company had the statutory obligation to evaluate a high DSM Case in the IRP, and that the Company should have evaluated a case that would achieve at least a 1% savings level.[32] The Commission included DSM directives in Order No. 2020-832, such as one that required the Company to conduct a rapid assessment of 1% energy savings in the years 2022 to 2024 in the 2020 Modified IRP. DESC worked closely with the Energy Efficiency Advisory Group ("EEAG"), and ultimately DESC's consultant, ICF, reached the conclusion that for the short term and at the portfolio level, "there is a path for DESC [to] achieve 1% savings in retail sales in years 2022, 2023 and 2024."[33] However, DESC noted that a three-month long "rapid assessment" of DSM programs was not a sufficient process for conducting long-term DSM analysis, and it stated that it was "beginning the process for a comprehensive evaluation in the form of a DSM potential study,"[34] which the Company included as the 2023 MPS.

In Order No. 2020-832, the Commission directed DESC to evaluate the cost-effectiveness and achievability of reaching higher levels of energy savings, including savings levels of 1.25%, 1.5%, 1.75% and 2%. The Company evaluated these levels of energy savings in the 2023 IRP and the Company also studied the impacts of achieving greater levels of electrification, energy conservation, and demand response. The Company stated it followed an underlying planning principle that "[c]ost effectiveness is a statutory requirement for DSM programs, and the Commission requires DESC to use 'cost effective, reasonable and achievable' as the standard for evaluating potential DSM savings in future IRPs."[35] DESC followed "best industry practice" and performed a DSM evaluation and MPS to identify various levels of EE energy savings.

In developing the 2023 MPS, the Company held seven EEAG meetings between November 2021 and November 2022, and in addition to hiring ICF to perform the 2023

[32] ORS's Report on DESC's 2020 Modified IRP, April 20, 2021, p. 12.
[33] DESC 2020 Modified IRP, February 19, 2021, p. 43.
[34] *Id.*
[35] 2023 IRP, p. 14.

MPS, the Company also selected Opinion Dynamics Corporation ("ODC") to analyze DESC's customer service territory in terms of the "types, ages, and condition of housing and other building stock and energy consuming equipment to provide reliable estimates of the opportunities and barriers for generating savings through DSM programs."[36]

The Company developed the following three DSM scenarios that it used for modeling purposes in the 2023 IRP:

- Low Case – DESC achieves 90% of the Medium Case EE savings.
- Medium Case – DESC offers revised programs identified in the 2023 Potential Study, which are based on the current DSM portfolio of programs and marketing plans, with modifications to participation based on the market characterization study, and utility benchmarking. Achieved .51% energy savings.
- High Case which is the maximum achievable potential scenario. Achieved 0.74% energy savings.

The Company characterized the Medium Case as having challenging but reasonable assumptions that accounted for the impacts of staffing issues, the pandemic, and recent supply chain disruptions. DESC explained the High Case assumed the most aggressive marketing scenarios, customer response rates, and energy savings levels that could be reasonably supported. DESC stated that ICF considered anything above the High Case to be "hypothetical because it would include measures that are not cost effective, and participation rates beyond the maximum achievable potential."[37]

DESC also evaluated the cost effectiveness and achievability of DSM portfolios with energy savings levels of 1%, 1.25%, 1.5%, 1.75%, and 2.0%, and the results are included in Appendix C of the 2023 IRP Report. DESC's concluded that any case that went beyond the Medium Case of 0.74% would require "non-cost-effective measures or unreasonable program participation assumptions."[38] Furthermore, in testimony associated with the 2023 IRP filed on behalf of DESC, Witness Durkee stated that ICF:

> …showed that the achievable reduction in energy consumption on DESC system varied between 0.74% and 0.46% based on reasonable and achievable rates of customer participation as established from multiple sources. The 1%, 1.25%, 1.5%, 1.75%, and 2% incremental annual savings scenarios require higher savings than the highest achievable levels for

[36] *Id.* at 14.
[37] *Id.* at 15.
[38] *Id.* at 16.

> DESC's service territory and therefore are above what could reasonably be achieved through DESC's DSM programs. These programs would need to include measures and/or programs that are not cost-effective and customer acceptance levels that are not supportable. [39]

The Company complied with Commission orders and conducted the MPS and incorporated the results as inputs to the 2023 IRP PLEXOS modeling analyses. Most of the cases that were performed relied on the Medium DSM Case assumptions; however, DESC conducted two PLEXOS sensitivity analyses, one using Low and the other using High DSM Case assumptions.

ORS reviewed the Company's DSM Sensitivity Cases and identified two errors, one that related to DSM cost assumptions, and another that related to the modeling of the EE load forecast impacts. The following tables summarize the Company's LNPV results from the DSM Sensitivity Cases. Table 8a reflects the results that the Company filed in the 2023 IRP Report and breaks down the costs into DSM, fixed, and variable production cost components.

Table 8a: Company Filed
DSM Build Plan and Scenario Evaluation LNPV ($000)

Market Scenario/ Build Plan	DSM Cost	Fixed Cost	Production Cost	Total
High DSM	30,900	366,903	1,465,055	**1,862,858**
Reference	30,900	380,792	1,472,025	**1,883,717**
Low DSM	28,764	350,351	1,489,015	**1,868,130**

The High DSM Case included the wrong DSM costs, as the DSM costs modeled in that case were the same assumptions as the Company modeled in the Reference Case. Also, the Low DSM Case included the wrong energy adjustment, as that case used the same energy adjustment that was associated with the High DSM Case.

While these errors should be corrected and the PLEXOS cases should be rerun, ORS estimated the changes that will occur in the results when the corrections are made in the

[39] Direct Testimony of Mr. Andrew Durkee, ICF on behalf of DESC, Docket No. 2023-9-E, April 4, 2023.

following table, Table 8b. The changes affected the DSM cost in the High DSM Case,[40] and the Production Cost in the Low DSM Case.[41]

Table 8b: ORS Adjusted
DSM Build Plan and Scenario Evaluation LNPV ($000)

Market Scenario/ Build Plan	DSM Cost	Fixed Cost	Production Cost	Total
High DSM	45,396	366,903	1,465,055	**1,877,355**
Reference	30,900	380,792	1,472,025	**1,883,717**
Low DSM*	28,764	350,351	1,513,977	**1,893,091**

*includes ORS estimated production cost adjustment

The revised results do not reflect the same ranking of cases. After the errors are corrected, the High DSM Case is the lowest cost case, the Reference Case is next highest in cost, and the Low DSM Case is the highest cost case. Based on the Company's results that contained errors, the Reference Case and the Low DSM Case rankings were reversed. ORS's results are aligned with expected results as Low DSM Cases usually reflect the highest cost results. ORS recommends that the Company correct the errors and provide the corrected results of the High and Low DSM Sensitivity Cases in Rebuttal Testimony.

Order No. 2020-832, Ordering Paragraph 8.e required DESC to "include DSM and Purchased Power as resource options in the 2021 IRP Update — if achievable — or 2022 IRP Update and future IRPs." In the 2023 IRP, DESC complied with this requirement and modeled solar purchase power resource options, and demand response ("DR") options as selectable resources.

To fully evaluate DR programs, as part of the MPS, ICF conducted an evaluation of numerous DR programs for both residential and commercial customers, with an emphasis on using DR to decrease the winter peak. The best performing programs, the Residential ToU and Smart Thermostat Opt-In programs, were modeled as selectable resources in the 2023 IRP. An Opt-in requirement was chosen for the Smart Thermostat program based on customer acceptance and flexibility considerations. The two DR programs were widely selected in all cases in the PLEXOS model runs.

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[40] ORS used the correct DSM cost for the High DSM Case. See ORS Information Request 6-4, which confirms the error.

[41] ORS's illustrative adjustment for the Low DSM Case assumed that the net remaining load after DSM would be higher using the correct DSM energy. ORS added in an additional cost for the additional energy that would have to be served in the Low DSM Case based on the avoided costs provided in the DSM Market Potential Study Appendix H. See ORS Information Request 6-6, which confirms this error.

Energy Efficiency and Demand Side Management Recommendations

C1. DESC should file results of corrected High and Low DSM Sensitivity Cases in Rebuttal Testimony.

D. Commodity and CO_2 Price Assumptions

1. Natural Gas Price Forecasts

In Order 2020-832, the Commission specifically directed DESC to use the Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO") low, reference and high gas prices in its production cost modeling. Beginning in DESC's 2020 Modified IRP, and continuing through DESC's 2022 IRP Update, the Company relied on AEO forecasts for the natural gas forecasts.

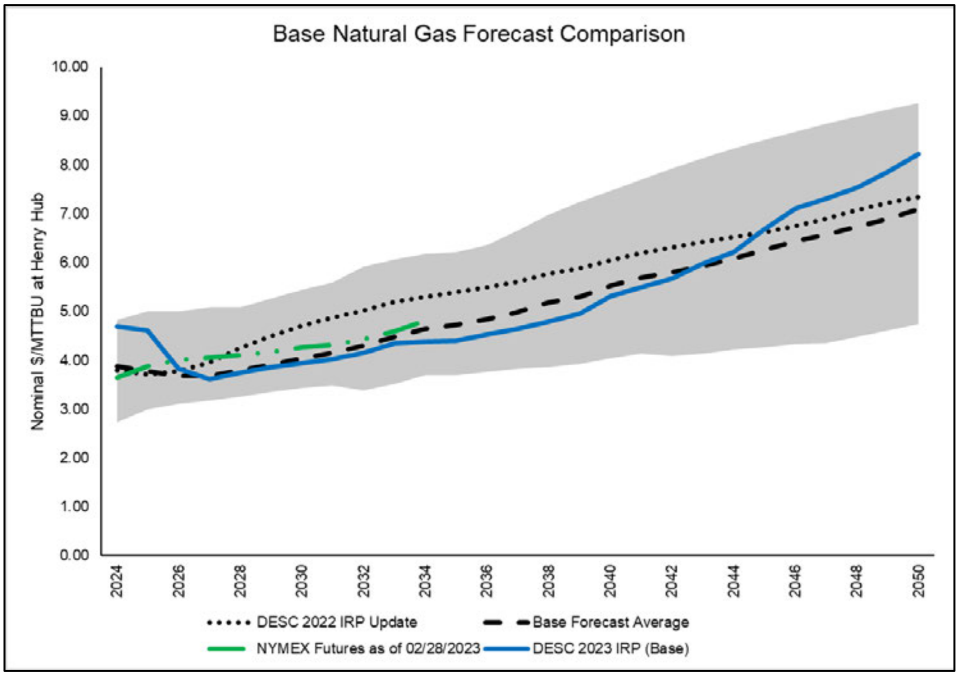
In the 2023 IRP, DESC revised the approach used to develop the natural gas price forecast by using NYMEX Henry Hub prices for the period of 2023 through 2025, and on forecasts developed by IHS Markit's ("IHS")[42] North American Power Market Outlook for the period of 2026 through 2050. For the high and low natural gas price forecast, DESC adjusted the base natural gas forecast by a percentage difference each year between the reference natural gas price forecast and the high or low natural gas price forecast provided by the EIA AEO.

The approach used by the Company is consistent with Order No. 2020-832, as the Commission preferred an industry standard approach that reflected long-term market dynamics, which the IHS forecast considers. The following figures compare the Company's natural gas price forecasts to other publicly available forecasts, including recent forecasts by Entergy Louisiana, Georgia Power Company, PacifiCorp, Santee

[42] IHS is now owned by S&P Global.

Cooper, EIA, and NYMEX.[43] The grey shaded area represents the range that the publicly available forecasts span over time, and in each of the three graphs (Base, High, Low) DESC's forecasts fall within the range of the publicly available forecasts.

Figure 4: Base Natural Gas Comparison ($/MBTU)



[43] NYMEX Futures - https://www.cmegroup.com/markets/energy/natural-gas/henry-hub-natural-gas-swap-futures-financial.html, accessed 02/28/23;
DESC 2023 IRP - https://www.dominionenergy.com/-/media/pdfs/global/company/desc-2023-integrated-resource-plan.pdf?la=en&rev=b9d24065d7e54ee2b622505d4928202a, p. 49;
DESC 2022 IRP - https://www.dominionenergy.com/-/media/pdfs/global/company/desc-2022-integrated-resource-plan.pdf?la=en&rev=3ab5313180f0412facbcbb2071f0f5e7, p. 74;
Georgia Power Company - https://psc.ga.gov/search/facts-document/?documentId=188519, Main Document, pp. 7-38;
EIA AEO2023 - https://www.eia.gov/outlooks/aeo/;
Entergy Louisiana - 2023 IRP Data Filing - https://cdn.entergy-louisiana.com/userfiles/content/irp/2023/2022-02-11-ELL-2023-Updated-IRP-Data-Filing.pdf, p. 19;
Santee Cooper - https://www.santeecooper.com/About/Integrated-Resource-Plan/presentations/Stakeholder-Meeting-4-FINAL-12-8, pdf p. 48;
Pacificorp - https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/PacifiCorp_2023_IRP_PIM_Feb-23-2023, pdf p.22.

Figure 5: High Natural Gas Comparison ($/MBTU)

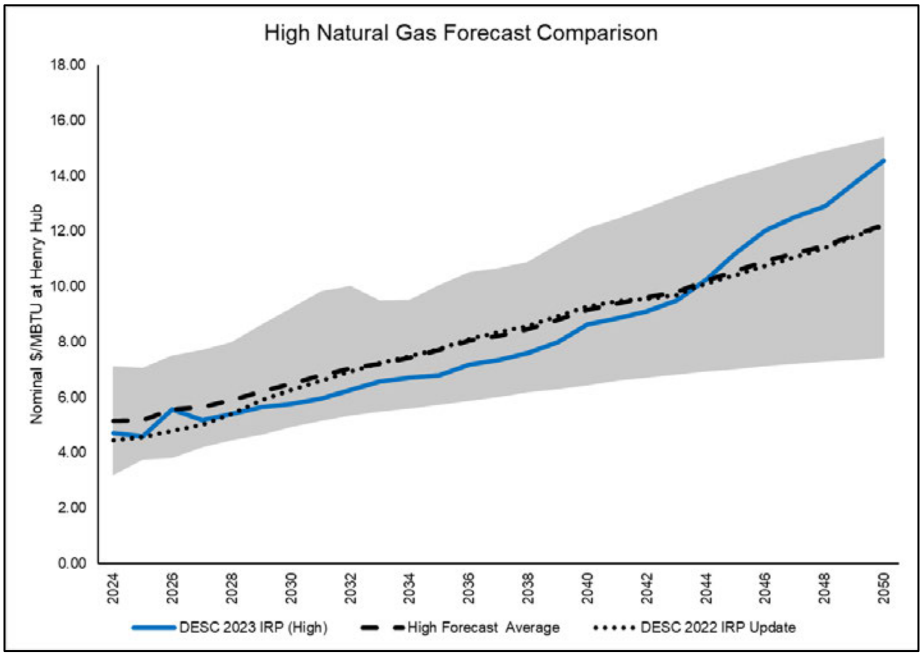
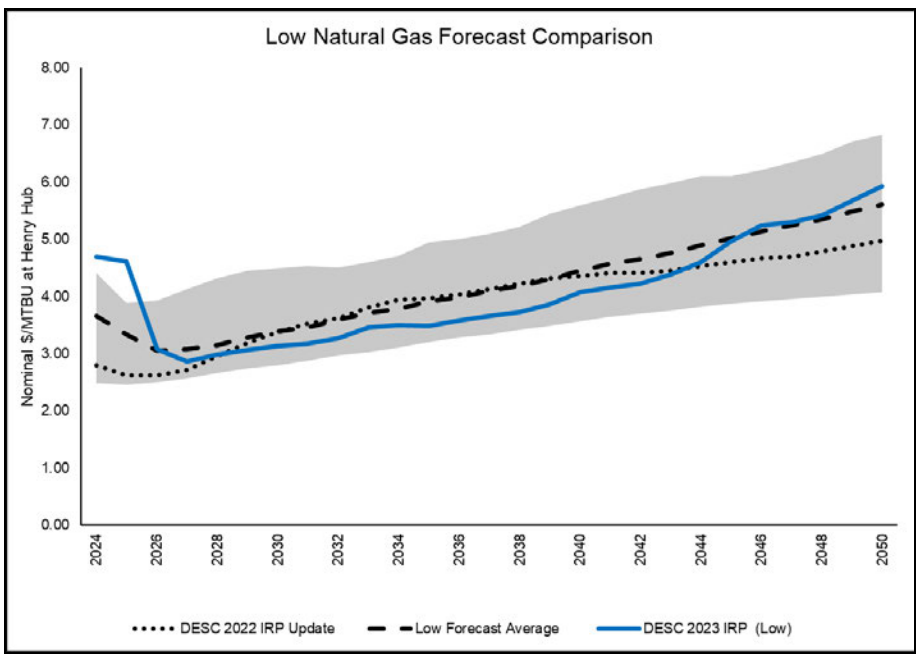


Figure 6: Low Natural Gas Comparison ($/MBTU)



At the start of the study period, the Company's forecasts (base, high, low) appear to be close to, but lower than the average of all of the forecasts, but the Company's forecasts become higher than, but still close to, the average of all of the forecasts in the later part of the study period. The forecasts are all within a range of reasonableness as depicted by the band of the other forecasts shown on the graphs.

In ORS's 2022 IRP Report, ORS's Recommendation One stated, "ORS recommends the Company provide both the commodity and delivered price assumptions when reporting its gas forecasts in future IRP reports." In the 2022 IRP Update, ORS was unable to clearly distinguish the Henry Hub commodity price forecast from the transportation components that are added to the commodity forecast to derive the fuel prices used to dispatch generating units. DESC addressed this at page 94 of the 2023 IRP Report:

> DESC has and will continue to provide all elements of the gas forecast including the applied basis differential, shrinkage and other transport charges. In addition to the base commodity prices forecast, delivered pricing includes these additional factors, varies with supply point, transportation path, and point of delivery, and is specific to each delivery time frame. As DESC will detail in the Stakeholder process, the delivered cost can be calculated in all cases with the information DESC provides in the IRP filing.

The Company's response satisfactorily addresses the ORS recommendation from the 2022 IRP Report.

2. Coal Price Forecasts

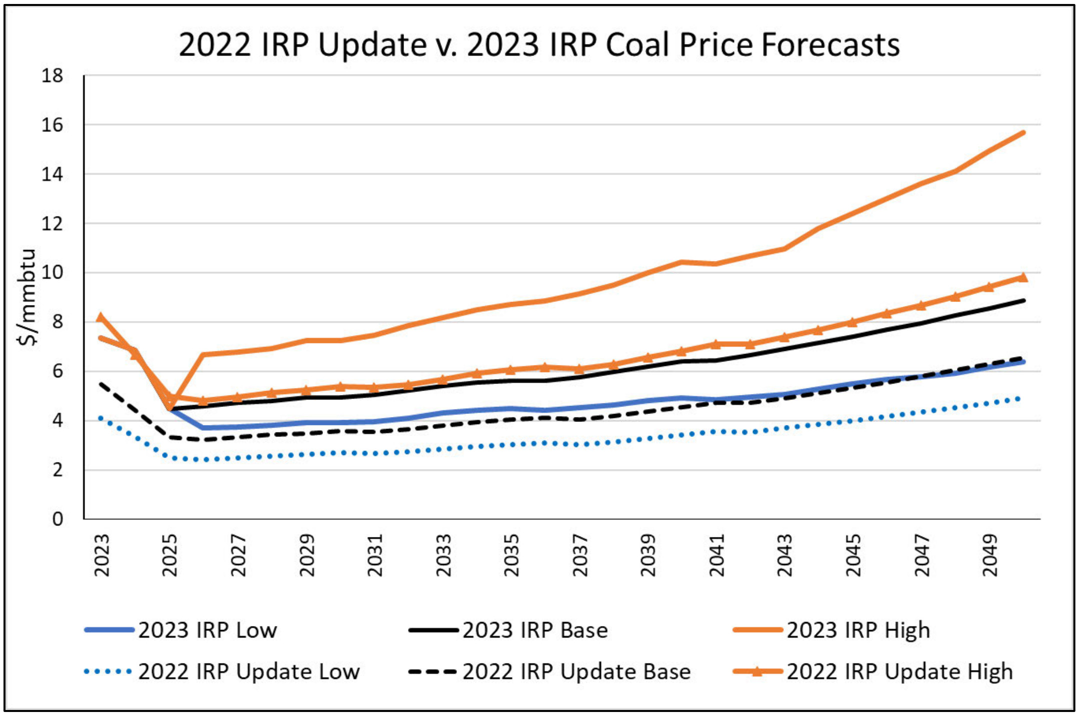
In the 2023 IRP, DESC modeled a Low, Reference, and High coal price forecast, and the forecasts were derived:

> ….based on the Company's direct knowledge of Appalachian coal contract prices for the years 2023-2025 based on its coal purchasing activities and IHS forecasts for years 2026-2050. High and low coal price forecasts are based on the difference between the reference and the high or low forecast provided by the United States Energy Information Administration in its Annual Energy Outlook. [44]

The 2023 IRP coal price forecasts (low, reference, high) are higher than the 2022 IRP Update coal price forecasts as can be seen in the following figure.

[44] 2023 IRP, p. 50.

Figure 7: Coal Price Comparison[45]



Significant world and national events have occurred and contributed to the Company's increasing coal price forecasts since the 2022 IRP Update. In testimony filed in the Company's recent fuel adjustment proceeding, Company witness Michael Shinn stated the following about the recent coal price changes:

> In January 2022, the forecasted FOB price for a ton of coal was indicated to be $91.00/ton. By July 2022 the market price of coal had increased to $175.00/ton. The market peaked in September at $205/ton before ending 2022 with a market price of $148.00/ton.[46]

Witness Shinn further explained that the Company expected coal prices to remain above the levels of recent years, which explains why the 2023 IRP coal price forecasts increased from the 2022 IRP forecasts.

The Company assumed a wider range between the low and reference, and between the reference and high coal price forecasts in the 2023 IRP compared to the ranges between the same forecasts in the 2022 IRP Update. The reason for this is partly explained by a

[45] *See* "2022 IRP Update Coal Prices.xlsx" from 2022 IRP Filing and "Fuel High Med Low.xlsx" from 2023 IRP Filing.
[46] Direct Testimony of Michael D. Shinn, Docket No. 2023-2-E, February 15, 2023, p. 6., l. 6.

change in the escalator used in the 2022 IRP Update versus the 2023 IRP. In the 2022 IRP Update, the Company derived the low and high coal price forecasts by scaling the reference forecast a fixed amount. Specifically, the Company reduced the base forecast by 25% to derive the low forecast, and added 50% to obtain the high forecast. In the 2023 IRP, the Company scaled the 2023 IRP base coal forecast by the difference between the EIA AEO base and high coal forecasts to create the 2023 IRP high coal forecast. Likewise, the Company scaled the 2023 IRP base coal forecast by the difference between the EIA AEO base and low coal forecasts to create the 2023 IRP low coal forecast.

Even though the Company has used a new approach to derive the 2023 IRP high and low coal price forecasts, the average difference between the base and low forecast is 27%, and the average difference between the base and high forecast is 52%, which are very close to the fixed 25% and 50% adjustments the Company used in the 2022 IRP Update. The Company's coal price forecast in the 2023 IRP is consistent with the Company's prior approach in the 2022 IRP Update.

3. Carbon Price Forecast

In the 2023 IRP, DESC modeled three CO_2 price forecasts. The low CO_2 forecast was set to $0/ton, the medium CO_2 forecast was set to $9.62/Mton starting in 2030, and was escalated to more than $45/Mton by the year 2050, and the high CO_2 forecast was priced 50% higher than the medium forecast, and started in 2028.[47] All three forecasts were based on information the Company obtained from the information vendor, IHS that produces the US Power Sector forecast.[48] The forecasts provided in the 2022 IRP Update remained the same in the 2023 IRP. Figure 8 below shows the DESC base forecast compared to the Base Cases utilized by other utilities across the U.S. (Georgia Power, PacifiCorp, Entergy Louisiana, AVISTA).

[47] 2023 IRP, p. 50.
[48] *Id.*

Figure 8: Industry Comparison of CO_2 forecasts

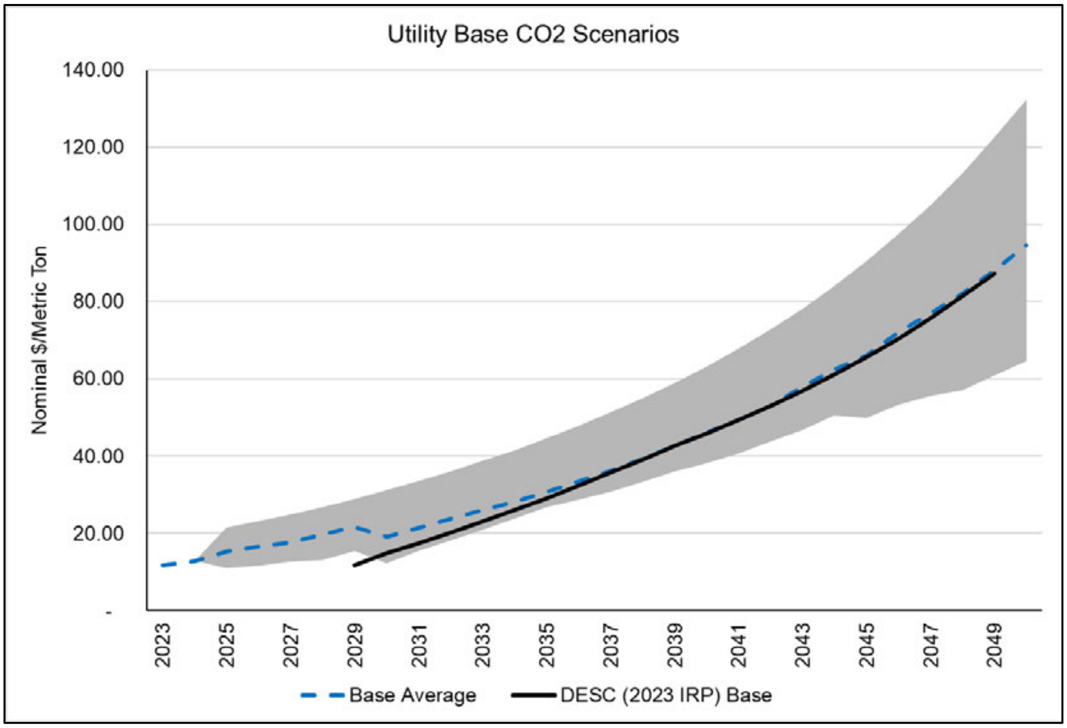
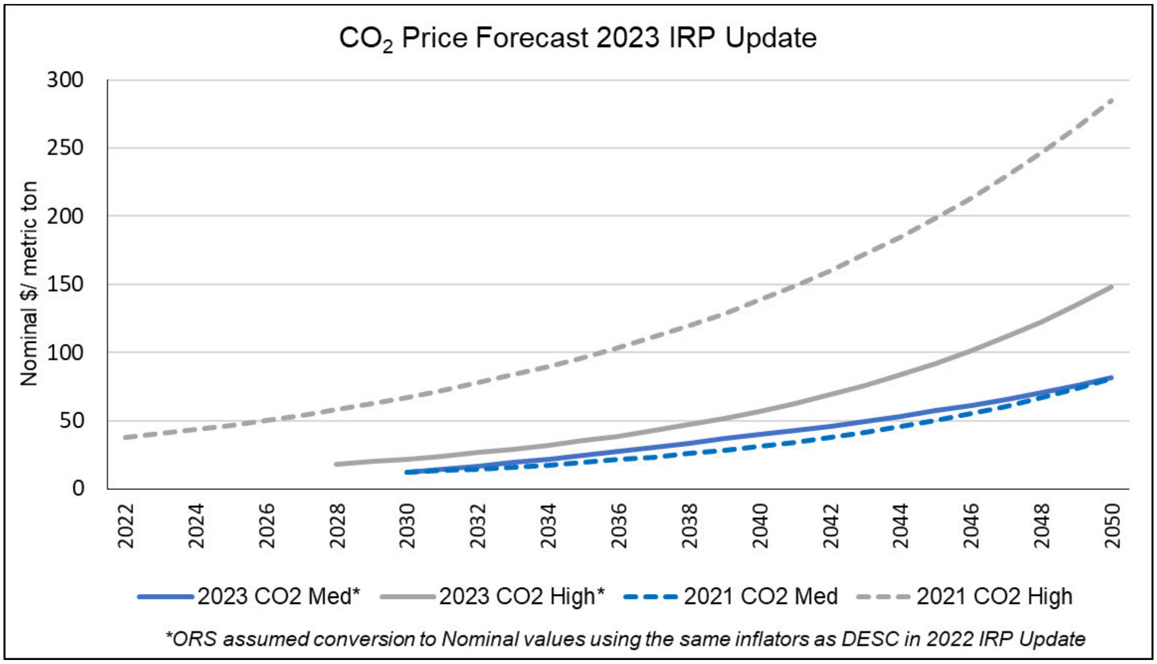


Figure 8 indicates that DESC's base forecast is reasonable versus the comparison forecasts. Figure 9 below provides a comparison of the CO_2 forecasts that DESC used between the 2021 IRP Update and 2023 IRP. The Company stated that the same low, medium, and high CO_2 scenarios were used in the 2023 IRP compared to the 2022 IRP Update.[49] ORS recommends that the CO_2 forecasts continue to be discussed in the Stakeholder Working Group. ORS's recommendation is based on the fact that a CO_2 tax has never been imposed at the Federal level or by the State of South Carolina, and there are renewable market incentives that could justify a lower price forecast, whereas pending CO_2 rules under the Clean Air Act could justify a higher price forecast.

[49] DESC response to ORS Information Request 2-14(c).

Figure 9: Carbon Price Comparison



<u>Commodity and CO_2 Price Recommendations</u>

D1. All commodity forecasts, including CO_2 forecasts, should continue to be discussed in the Stakeholder Working Group. ORS's recommendation regarding CO_2 forecasts is based on the fact that a CO_2 tax has never been imposed at the Federal level or by the State of South Carolina, and there are renewable market incentives that could justify a lower price forecast, whereas pending CO_2 rules under the CAA could justify a higher price forecast.

E. Renewable Energy and Energy Storage Forecast

1. Capacity Value Modeling

The capacity value that DESC attributed to renewable resources has been an issue that parties originally raised in the 2020 IRP. In Order No. 2020-832, Ordering Paragraph 6.b.iii., the Commission required the Company to:

> Correct the incremental flexible solar PPA capacity value assumptions to reflect the ELCC value specific to the existing system penetration level of incremental flexible solar PV.

In the 2020 Modified IRP, the Company updated the capacity value attributed to solar resources and used 11.8% as the capacity value for existing solar resources, and 4.25%

for incremental solar resource additions. The Company continued to use those values in the 2021 and 2022 IRP Updates. The Company stated in the 2022 IRP Update that for future integrated resource planning, DESC would hire a third-party consulting firm to conduct a probabilistic Reserve Margin and ELCC study to update these assumptions. The Company hired Astrapé to perform the reliability studies.[50] Astrapé determined the appropriate reserve margin target for DESC, and the capacity value of resources, based on an ELCC study, including for battery storage and solar resources.

Based on the latest probabilistic ELCC study, Astrapé determined that incremental solar resources would provide the System with 2.7% capacity value, which is lower than the 4.25% capacity value that the Company assumed in prior IRPs. The lower result is reasonable given the more rigorous ELCC study and the fact that solar resources do not typically generate much power during peak morning winter hours when capacity is needed most. In addition, Astrapé determined the value of solar capacity declines as more solar resources are added to the System. Astrapé determined the first 100 MWs of incremental solar additions would receive the 2.7% capacity value, and the capacity value would drop as more solar resources are added to the System. For example, Astrapé determined that any new solar capacity additions above the approximately 1,110 MW already on the DESC System, would receive .5% capacity value.[51] The results of the Astrapé study are consistent with what other electrical utilities have attributed to incremental solar resource additions for capacity value.[52]

For Battery Storage facilities, Astrapé concluded that the next 200 MWs of four-hour batteries would provide 90% capacity value given that capacity may be needed longer than for four-hour stretches of time, particularly during severe winter weather events. Astrapé determined the capacity value would drop to 80% as additional battery storage resources are added. Again, the reduction in capacity value as additional battery storage resources are added appears to be reasonable and is consistent with the findings of other utilities across the country.[53]

The Company considered OSW resources as selectable resources available beginning in the year 2040. In the 2022 IRP Update Report, ORS recommended that additional consideration be given to the capacity valuation of OSW resources, given their recent introduction in DESC's expansion plan modeling process. The Company assumed the capacity value of OSW resources would be 30% in the 2022 IRP Update. In the

[50] 2022 IRP Update, p. 77.
[51] 2023 IRP, Table 7, p. 24.
[52] Georgia Power 2022 IRP, Vol 1, ELCC Study (filed January 31, 2022, Georgia Public Service Commission Docket 44160).
[53] *Id.*

Company's January 19, 2023 responsive comments to the 2022 IRP Update Report, the Company indicated that additional discussions would take place in stakeholder meetings regarding the capacity value of OSW resources. ORS will continue to monitor the need for additional OSW modeling support and updates in future IRPs. The Company maintained the availability date of 2040 for OSW resources, and there is plenty of time to further evaluate OSW resources and modeling assumptions before OSW may be added to DESC's System.

2. Interconnection Limit and Build Limits

The Company's modeling assumption regarding the inclusion of solar resources as selectable resources has evolved over time. For example, in the 2021 ORS Report, ORS commented that:

> The Company's inclusion of solar PPAs at the Commission-required prices were utilized only for the 400 MW of solar additions in 2023. The 1,500 – 1,600 MW of later solar additions were all assumed to be self-build options.[54]

As such, ORS recommended for future IRPs and IRP Updates the Company allow market priced PPA solar resources to be treated as selectable generic resource options throughout the entire study period rather than as a one-time selection in 2023. Beginning in the 2022 IRP Update, the Company addressed this by modeling both self-build and PPA solar resources as selectable resource options.

For the 2023 IRP, the Company assumed that either utility-owned or PPA solar resources starting in 2026. The decision to set 2026 as the earliest date when new solar resources may be added seems reasonable when accounting for factors such as the need to conduct an RFP, regulatory requirements, construction build times, and interconnection queue requirements.

In the 2023 IRP, the Company limited the amount of solar and other generic resources that could be added over the study period. It is reasonable to include such inputs, because there are limits to the number of generic resources that can be added to a utility's system in any given year or over a planning period. Optimization models can have very long runtimes, and incorporating limits on the number of generic resources that could be added in an optimization run is a useful way to manage runtimes.

[54] ORS 2021 IRP Update Report, p. 39.

The following describes the cumulative limits DESC set for the number of solar resources PLEXOS could add over the study period.[55] DESC stated the cumulative limits were selected based on the Company's experience with solar units already added to the System, and the cumulative limits did not prevent PLEXOS from adding a reasonable amount of additional economic solar resources.[56] The following table was developed from a review of PLEXOS input data for each of the Core Cases.[57]

TABLE 9

Selectable Solar MW available (PPA + Utility Owned)	2026-2035 (IRA)	2036- 2050	Total Allowable Additions	Total Selected MW
Reference	3,000	2,700	5,700	5,025
High Fuel	3,000	4,200	7,200	6,750
Zero Carbon	3,000	2,700	5,700	4,275
CarbonConst70	3,000*	3,000	6,000	6,000
CarbonConst85	3,000*	4,500	7,500	7,500

*no IRA pricing reporting category

The table is broken into two time periods corresponding to when the Company assumed that the IRA impacts on solar pricing would be in effect. The Company reduced the capital cost of solar resources during the 10-year period of 2026 to 2035 to account for tax benefits associated with the IRA. Between 2035 and 2050, the Company assumed that the IRA tax benefits would be eliminated, and the Company modeled higher solar capital costs during that 15-year period.

For most of the cases that the Company ran, it modeled the data such that the solar resources selected during the IRA period (2026–2035) were reported as "solar IRA" resources, and the solar resources selected after that were reported as just "solar" resources. However, in the Carbon Constrained Cases, the Company just reported all solar resources as "solar." This was just a reporting issue, as the Company still incorporated the proper tax benefits in the applicable years in the Carbon Constrained Cases.

In addition to modeling cumulative limits, DESC modeled annual limits to the number of solar resources that could be added. DESC sized generic solar resources at 75 MW each, and the annual limit was that no more than four 75 MW or 300 MWs of solar resources

[55] Response to ORS Information Request 1-23(c).
[56] Response to ORS Information Request 2-11(c)
[57] Response to ORS Information Request 1-23(c). The Company's discovery response only supplied information for the Reference Case. ORS obtained the other assumptions from the PLEXOS database.

could be added in any year between 2026 and 2050. The Company asserted the modeling limits were reasonable based on the Company's experience and engineering judgement. The following table depicts the solar resources that have been added or will be added to DESC's System up to 2024. The table includes solar and battery hybrid combinations.[58]

Table 10

Solar PPAs	Nameplate Capacity Solar (MW)	Nameplate Capacity Battery (MW)
Solar resources acquired prior to 2020 (MW)	571	
Solar resources aquired 2020 through 2022 (MW)	402	
Solar and battery acquired 2023 (MW)	136	34
Solar and battery acquired 2024 (MW)	66	66
Total Solar Under Contract (MW)	**1,174**	
Solar Acquired 2020 - 2024 (MW)	604	
Number of years	5	
Average Solar MWs Acquired 2020 - 2024 (MW)	121	

Table 10 indicates the Company contracted for a total of 1,174 MW to be on the System by the end of 2024. Between the five year period of 2020 to 2024, the Company will acquire 604 MW of solar capacity, which amounts to an average of 121 MW per year. Given the average addition of 121 MW of solar resources per year to DESC's System, the Company's selection of 300 MW as the annual solar capacity addition limit is reasonable.

3. Integration Charges

In Order No. 2020-832, the Commission required the Company to "[a]ssume integration costs of $0.96 / MWh for solar PV, until an updated, Commission-approved methodology for calculating solar integration costs is available."[59] The interim value was to be revised in a future Integration Study. In Docket No. 2021-88-E, DESC retained Guidehouse to perform an updated study to determine the cost of integrating different levels of solar resources on the System. Guidehouse determined that additional operating reserves would be required to integrate up to 973 MWs of solar resources on the System, at an added cost of $1.80/MWh.[60] Guidehouse determined that even higher integration costs would be required to add additional solar resources beyond 973 MWs to the System. In

[58] 2023 IRP, p 37.
[59] Order No. 2020-832, p. 90.
[60] Direct Testimony of Peter David, Docket No. 2021-88-E, June 29, 2021, p. 26, l. 7.

Order No. 2022-329, the Commission established a variable integration charge of $1.80/MWh for all amounts of solar resources.[61]

In the 2022 IRP Update, DESC relied on $1.80/MWh as the solar integration cost for Solar PPA resources.[62] In the 2022 IRP Update, DESC only included integration costs associated with PPA resources, and stated that integration costs would not be appropriate for utility-owned projects because "….the utility would essentially be paying itself."[63]

DESC continued the same modeling treatment in the 2023 IRP, and in discovery, the Company stated that in addition to modeling solar integration costs associated with PPA resources, the Company also accounted for operating reserve impacts (spinning and regulating reserves) associated with all solar resources (utility-owned and PPA) in the PLEXOS modeling that was performed.[64]

The inclusion of integration costs and additional operating reserves for solar PPA resources could lead to the selection of too few solar PPA resources and overstatement of the costs of acquiring PPA resources. However, the Company's results indicate a substantial amount of solar PPA resources were selected, which mitigates the possible overstatement of costs. ORS recommends that DESC discuss the appropriate modeling of integration costs for renewable resources in the Stakeholder Working Group.

4. Federal Legislation and EPA Rule Updates

Inflation Reduction Act of 2022

The IRA was passed in August 2022 and extended or added for the first time, federal investment tax credit ("ITC") and production tax credit ("PTC") benefits associated with wind, solar, and stand-alone battery storage resources.[65] The tax changes should be accounted for in the utility resource planning studies. In the 2023 IRP, DESC assumed solar resources would receive a PTC of $25 per MW and battery storage resources would receive an ITC of 30% on 85% of the total project cost.[66] The Company incorporated IRA tax benefits for various resources between 2026 and 2035.

[61] Docket No. 2021-88-E, Order No. 2022-329, May 2, 2022, Ordering Paragraph 11, p. 74.
[62] ORS 2022 IRP Update Information Request 3-3(a), and ORS 2023 IRP Information Request 1-23(b).
[63] ORS 2022 IRP Update Information Request 3-3(e).
[64] ORS 2023 IRP Information Request 2-10(d).
[65] https://www.congress.gov/bill/117th-congress/house-bill/5376.
[66] 2023 IRP, p. 22.

ORS encourages the Company to monitor federal legislative activity, and at the appropriate time, update any assumptions to adjust for the known changes in PTC/ITC tax benefits.

Infrastructure Investment and Jobs Act

DESC described the Infrastructure Investment and Jobs Act ("IIJA") starting on page 20 of the 2023 IRP Report. As of the time of the filing of the 2023 IRP Report, DESC had not received feedback from the U.S. Department of Energy ("DOE") regarding a "Concept Paper" submitted by DESC in December 2022 related to the Grid Resilience and Innovation Partnerships ("GRIP") program under the IIJA.[67] The GRIP program provides funding opportunities to encourage the expansion and modernization of the electric grid.[68] DOE encouraged DESC to submit a grant application for the project that DESC named the South Carolina Optimization for Resilient Energy ("SCORE") Project.[69] DESC submitted an application on April 4th, and expects selection notifications this summer, and a possible award to be made by the fall.

EPA Notice of Proposed Rule Making

The EPA issued proposed GHG Standards and Guidelines for Fossil Fuel-Fired Power Plants on May 23, 2023, under Section 111 of the CAA ("Proposed GHG Rules").[70] The EPA is currently receiving comments on the proposed rule.

One part of the proposed rule provides for new performance standards that must be met by new or reconstructed CT and CC resources. These requirements depend on whether the new units will operate as base, intermediate, or peaking units, and allow the unit owners a choice of two different compliance pathways, either the use of carbon capture and sequestration technology ("CCS"), or the use of co-firing with low-GHG hydrogen based on a specified timeline.

The proposed rule provides guidelines for existing CT and CC units. The EPA broke this category into two segments that depend on the size and frequency of operation of the unit. For large (>300 MW) and frequently operated (>50% capacity factor) CT and CC units, the EPA is proposing two pathways, either the use of CCS, or the use of low-GHG

[67] 2023 IRP, p. 21.
[68] *Id.*
[69] Response to ORS Information Request 6-7.
[70] https://www.federalregister.gov/documents/2023/05/23/2023-10141/new-source-performance-standards-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed

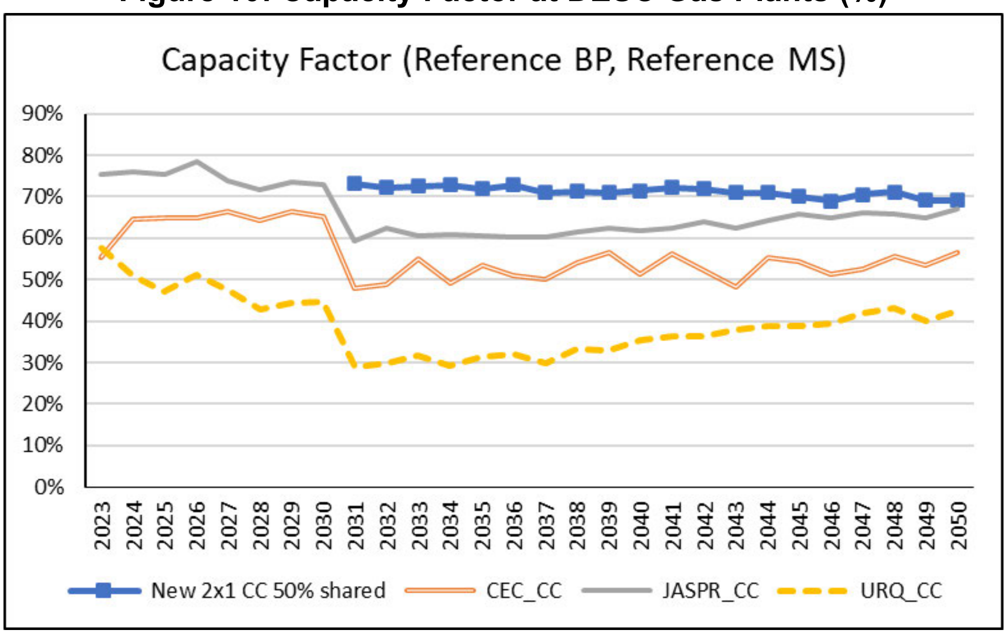
hydrogen co-firing based on a specified timeline. For smaller less frequently used CT and CC units, the EPA is soliciting comments on how to establish emission guidelines.

Another part of the proposed rule includes guidelines for existing steam generating units, with guidelines that differ depending on how long the owner plans to keep the units in operation. For units that will operate over the long-term, the EPA proposes similar requirements as those that apply to new CT and CC units. For units that will operate over the medium-term, the EPA proposes guidelines that allow for 40% co-firing with natural gas, and units that will operate over the near-term, the EPA proposes the owner just perform routine O&M.

DESC did not account for impacts associated with the Proposed GHG Rules, as the Company stated that it "will perform an analysis when the proposed standards become law,"[71] and there is no certainty at this time that the Proposed GHG Rules will become law. However, if the Proposed GHG Rules were to be implemented, DESC's existing coal, CC, and proposed new CC resources may be impacted, which may affect DESC's Preferred Plan, and particularly the Company's future plans for the addition of a new Joint CC in 2029.

The chart below plots the expected capacity factors of DESC's CC plants, existing and new, for DESC's Preferred Plan, over the study horizon.

Figure 10: Capacity Factor at DESC Gas Plants (%)



[71] Response to ORS Information Request 6-3.

Figure 10 demonstrates most of DESC's CC units may be affected by the Proposed GHG Rules. The Proposed GHG Rules may also impact the operation of DESC's coal units, depending on when the Company finalizes the retirement decisions for Wateree and Williams.[72] ORS recommends DESC discuss the possible impacts of the Proposed GHG Rules in Rebuttal Testimony, especially in light of the joint resource decision, and the Wateree/Williams retirement decisions.

Renewable Energy and Energy Storage Forecast Recommendations

E1. DESC should discuss the appropriate modeling of integration costs for renewable resources in the Stakeholder Working Group.

E2. DESC should discuss potential impacts of the proposed EPA CAA Section 111 Regulation of GHG Emissions from Fossil Fuel-Fired EGUs rule change in Rebuttal Testimony.

F. Retirements and New Resource Decisions

1. Generic Resource Options

DESC identified the following generic resource types considered for selection in the 2023 IRP.[73] DESC relied on the National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") for some of the renewable energy cost assumptions, as indicated below in Table 11.

[72] For reference, in 2027, the Wateree and Williams capacity factors are 3% and 41%, respectively.
[73] 2023 IRP, Table 13.

Table 11: Expansion Plan Unit Options

Available Resources	2022 IRP Update		2023 IRP	
	Capacity (MW)	Capital Cost ($2022/kW)	Capacity (MW)	Capital Cost ($2022/kW)
New 1x1 Combined Cycle *	553	1,857	650	1,452
New 2x1 Combined Cycle *	1,114	1,437	1,325	1,163
New 2x1 Combined Cycle 50% Shared *			662	1,163
New 3x1 Combined Cycle *			1,950	941
New CT Aero 1x *	114	1,760		
New CT Aero 2x *			114	1,898
New CT Frame 1x *	262	725	262	1,402
New CT Frame 2x *	523	725	523	1,154
New Small Modular Reactor *	275	6,488	274	12,354
New Solar **	75	1,226	75	1,240
New Solar PPA **	75	1,226		
New Solar with Battery **	75	1,966		
New Solar with Battery PPA **	75	1,966		
New Battery 4 hour **	37.5	1,387	100 ***	1,459
New Battery 8 hour **	37.5	2,642		
New Off Shore Wind **	100	4,323	100	4,323

* Dominion Energy Services developed pricing, escalation assumption for 2023 is 1.89%, 2022 was 1.97%

** Escalation assumption for 2023 is 2.50%, Renewable Pricing sourced to NREL 2022 ATB

*** Value from Table 13 2023 IRP provides an incorrect value; Plexos and Neely table 5 show 100 MW

The 2x1 CC resource included in the 2023 IRP is larger than the 2x1 CC resource that was included in the 2022 IRP (1,325 MW vs. 1,114 MW). The Company included a variation of a 2x1 CC, in which it would be a 50% owner of the resource shared with Santee Cooper. A joint memorandum of understanding ("MOU") was signed on November 28, 2022, and indicated that both companies have the same interest in owning a CC resource, which would enter service around the same time. The MOU stated that a joint project could provide economies of scale benefits for both companies, and DESC proposed to locate the unit at the Company's former Canadys Station site.[74] The MOU stated the two companies seek to investigate and analyze the joint development project, but few additional details were provided by DESC about the progress of the investigation. Issues that must be investigated include site selection, fuel availability, transmission impacts, environmental considerations, economic impacts, and schedule.

[74] Response to ORS Information Request 1-14.

Appendix B contains assumptions about generic resource options that DESC considered in the 2023 IRP, and compares those assumptions to both DESC's 2022 IRP assumptions, and to assumptions from peer utility documents and other industry sources, including the 2023 EIA AEO Report and Lazard's 2023 Levelized Cost of Energy Report. Collectively the comparison assumptions are referred to in this Report as the "other sources." The following observations are based on a review of information in Appendix B:

1. CT modeling - The CT capital cost assumptions the Company used in the 2023 IRP are higher than what the Company assumed in the 2022 IRP, and higher than the assumptions used by the other sources. For example, DESC increased the cost of the 1x Frame CT by 93% in the 2023 IRP. The escalation in pricing may have biased the selection of CT resources. ORS recommends the Company justify the significant cost increase associated with CT resources in Rebuttal Testimony.

2. CC modeling - The Company's assumed cost of CC resources declined in the 2023 IRP compared to the 2022 IRP Update. For example, the 2x1 CC decreased in price by about 22%. The decrease in cost is reasonable and consistent with the costs that the other sources used for CC resources. However, the Company also decreased the winter heat rate assumption for the 1x1 CC unit to [redacted] Btu/kWh, which is low, especially compared to the other sources, and equates to about a [redacted]% efficiency (3,412 / [redacted]).[75] An efficiency value of this level for a CC is possible, as there are industry reports of CC efficiency levels close to that level.[76] ORS recommends the Company clarify in Rebuttal Testimony if the CC technology assumptions used are consistent with this type of industry report, and if this is the technology that the Company is considering for the joint CC unit.

3. CC differences compared to Santee Cooper – There are significant differences between the CC assumptions used by DESC in the 2023 IRP, and the assumptions used by Santee Cooper in their 2023 IRP. The assumptions should ultimately be aligned given that both companies are considering building a shared resource.

4. Solar Prices – In the 2023 IRP, the Company relied on updated renewable energy cost assumptions from the NREL 2022 Annual Technology Baseline ("ATB"), including tax benefits. The Company compared the NREL data to bid price information obtained from the Independent Evaluator's ("IE") final report in the Urquhart Replacement All-Source RFP that was published on March 27, 2023, and concluded that "NREL Solar Only values are comparable and only slightly lower

[75] The Company's heat rate assumptions for the 2x1 and 3x1 CC generic resources are also low.
[76] Power Magazine Article, "Another World Record for Combined Cycle Efficiency", October 1, 2018, https://www.powermag.com/another-world-record-for-combined-cycle-efficiency/.

(approximately 10%) than the winning bid in the Urquhart RFP."[77] The renewable energy cost assumptions the Company used in the 2023 IRP are reasonable and consistent with the other sources included in Table B-6 below.

5. Battery Storage Prices – DESC stated, "Battery values provided in the Urquhart RFP process were greater than twice that of the NREL values."[78] ORS reviewed the Urquhart results and determined that while there was a range of bid prices, some were twice as high as the NREL values. Given DESC's position, ORS recommends the Company perform one additional modeling sensitivity of the Reference Case with higher battery storage assumptions. Also, the Company noted in response to Sierra Club Request 3-4 that it found an error in the fixed Operating and Maintenance ("FO&M") cost that was modeled for the 85% battery storage resource. The Company stated that it incorrectly used the FO&M cost of an 8 hour battery instead of the FO&M cost for a 4 hour battery. ORS recommends the FO&M assumption be corrected, as well, in the new sensitivity case.

6. Small Modular Reactors ("SMRs") – Since the 2022 IRP Update, the Company approximately doubled the capital cost assumption for building an SMR resource. The Company provided no support for the capital cost assumption for SMR resources in response to ORS discovery.[79] ORS expects the capital cost assumption for SMRs will be refined in future IRPs, as SMRs are not expected to be viable until later in the 2030 time period or in the 2040s.[80]

2. Preferred Portfolio Analysis

In the 2023 IRP, DESC developed various Build Plans (portfolios) that included new resources to be built over the planning horizon under various scenarios. The following table describes the Build Plans included in the 2023 IRP.

[77] Response to ORS Information Request 2-9(a).
[78] Response to ORS Information Request 2-9(b).
[79] Response to ORS Information Request 2-5(c).
[80] 2023 IRP, p. 23.

Table 12: Summary of Build Plans Developed

Build Plan (14)	Type	Market Scenario for Optimization	Fuel	CO_2 Price	Load Forecast	DSM	Williams Retirement
Reference	Core	Reference	Med	Med	Ref	Med	2030
High Fossil Fuel Prices	Core	High Fossil Fuel Prices	High	Med	Ref	Med	2030
Zero Carbon Cost	Core	Zero Carbon Cost	Med	Zero	Ref	Med	2030
70% CO2 Reduction	Core	Reference	Med	Med	Ref	Med	2030
85% CO2 Reduction	Core	Reference	Med	Med	Ref	Med	2030
Electrification	Sensitivity	Electrification	Low	Zero	High	Med	2030
Energy Conservation	Sensitivity	Energy Conservation	High	Med	Low	Med	2030
Aggressive Regulation	Sensitivity	Aggressive Regulation	High	High	High	Med	2030
High DSM	Sensitivity	High DSM	Med	Med	Ref	High	2030
Low DSM	Sensitivity	Low DSM	Med	Med	Ref	Low	2030
Wateree Battery	Supplemental	Reference	Med	Med	Ref	Med	2030
Wateree CT	Supplemental	Reference	Med	Med	Ref	Med	2030
Williams 2047	Supplemental	Reference	Med	Med	Ref	Med	2047
High Fuel Williams 2047	Supplemental	High Fossil Fuel Prices	High	Med	Ref	Med	2047

The Build Plan column indicates that the Company developed fourteen (14) different Build Plans based on PLEXOS optimization runs that included different assumptions about future market conditions or Market Scenarios. The Market Scenario variables include assumptions about fuel prices, CO_2 prices, load forecasts, DSM cases, and Williams retirement dates. The PLEXOS derived expansion plan results for the first case, the Reference Build Plan, is summarized as follows:

Table 13: Reference Case Build Plan Summary

Reference Build Plan (MW)									
	CC	CT Aero	CT Frame	Solar	Battery	SMR	Off-Shore Wind	Net MW	Reserve Margin Range
2023-2026	0	0	0	150	0	0	0	150	29 - 32
2027-2031	662	0	0	1,425	400	0	0	2,487	21 - 30
2032-2040	0	0	523	2,100	900	0	0	3,523	21 - 29
2041-2050	0	0	523	1,350	300	0	0	2,173	20 - 28
Totals	662	0	1,046	5,025	1,600	0	0	8,333	

Appendix C contains the same table, but for all five of the Core Build Plan Cases. The Reference Case Build Plan Summary indicates that some solar resources are added in the 2023 to 2026 time period, and two other capacity resource additions are planned in the 2027 to 2031 time period. The 400 MW battery storage resource is assumed to be the replacement for the Wateree capacity when it retires at the end of 2028. The 662 MW CC resource is assumed to be the replacement for the Williams capacity when it retires at the end of 2030, and it is assumed to be a 50% share of a 1,324 MW jointly owned unit with Santee Cooper.

Once the Build Plans were developed, the expansion plans were finalized, and production cost runs were made. Production cost runs for the five Core Build Plans were evaluated based on three Market Scenarios, referred to as the Reference, High Fuel, and Zero Carbon Cost scenarios. In all, fifteen (15) production cost studies were performed to evaluate the resilience of the Core Build Plans, especially to determine how well they would perform against unknown and variable future scenarios.

The remaining nine Build Plans were evaluated as sensitivity or supplemental cases to evaluate one specific change in market conditions. In total twenty-four (24) production cost cases were analyzed.

The Company derived thirty-year LNPV incremental costs for each case, and then compared those costs to find the lowest cost resource plans. Some utilities evaluate resource plans with a net present value ("NPV") calculation instead of a LNPV calculation. It makes little difference whether LNPV or NPV results are evaluated, as the two results are derived from each other, and the conclusions reached would be exactly the same.

There is a slight miscalculation in the Company's LNPV results, which ultimately had no impact on the Company's conclusions. The Company ran PLEXOS for a twenty-eight (28) year study period, performed a 10-year end effects calculation, and then developed levelized costs based on the assumption that the study period was thirty (30) years.[81] However, the proper levelization calculation should have been performed over the thirty-eight (38) year study and end effects period (28 + 10). Again, this error did not substantively impact the 2023 IRP. However, in the future, the Company should develop levelized values that are consistent with the study parameters.

The LNPV results that the Company derived for the fifteen (15) Core Cases are presented in the following table.

[81] Refer to ORS Information Request 2-1. ORS performed alternative levelization calculations to validate that the study conclusions did not change when the proper calculation was performed.

Table 14
LNPV Results – 15 Core Cases
($Millions)

	Market Scenario		
Build Plans	**Reference**	**High Fossil Fuel Prices**	**Zero Carbon Cost**
Reference	**$1,884**	**$2,177**	$1,809
High Fossil Fuel Prices	$1,954	$2,200	$1,838
Zero Carbon Cost	$1,895	$2,187	**$1,774**
70% CO2 Reduction	$2,072	$2,308	$2,000
85% CO2 Reduction	$2,393	$2,588	$2,338

These results indicate that, based on costs alone, the Reference Build Plan would be the best resource plan (least cost) for DESC if either the Reference or the High Fossil Fuel Price futures were to prevail, and the second best plan for DESC if a Zero Carbon Cost future were to prevail.

The Company also evaluated the Cases based on other metrics pursuant to Commission Order No. 2020-832 that required the Company to work with the Stakeholder Group to examine the implementation of other risk metrics in future IRPs.[82] Beginning in the 2021 IRP Update, the Company used the following metrics to provide "a systematic and quantitative assessment of the factors relevant to the selection of a preferred resource plan."[83]

- Levelized Cost
- CO_2 Emissions
- Clean Energy
- Fuel Cost Resiliency
- Generation Diversity
- Reliability Factors
- Mini-Max Regret Analysis
- Cost Range Analysis

DESC's Table 39 on page 70 of the 2023 IRP Report contains ranking results of the five Build Plans of the Core Cases across the eight metrics listed above. Additionally, Table

[82] Order No. 2020-832, Docket No. 2019-226-E, p. 64.
[83] DESC 2021 IRP Update, p. 39.

39 includes the ranking results of one additional metric, a 30-year cumulative CO_2 emissions metric. The CO_2 emissions metric is duplicative of the 2050 CO_2 emissions metric. The Company recognized this duplicity at page 66 of the 2023 IRP Report, as it noted "The results are similar." The Company provided no explanation why two "similar" metrics appear in the ranking results table (Table 39), and the Company even incorrectly stated that the table contained eight metrics.[84]

The Company referenced the metrics in the following assessment of the Perferred Plan:

> Based on its review of the needs of the system and the PLEXOS modeling contained in this 2023 IRP, DESC has determined that the Reference Build Plan is the preferred build plan to guide its planning decisions at this time. The Reference Build Plan is the lowest cost option with the lowest regrets score of any plan under Reference Market Scenario which represents DESC's assessment of the likely conditions to be encountered during the planning period.[85]

ORS performed additional analysis of the Company's results to assess the reasonableness of the Company's conclusion that the Reference Build Plan should be the Company's Preferred Plan. DESC's Ranking Summary Table (Table 39) is replicated below, but two additional columns have been added to the far right. The "Average" column is an equally weighted average calculation, and the far right column ("Average w/o duplicative CO_2 metric") is also an equally weighted average calculation, but calculated excluding the Cumulative CO_2 metric, which is the same as the 2050 CO_2 metric.

When the duplicative metrics are included, and assuming that all metrics are equally weighted, the Average column indicates that the 85% CO_2 Reduction Case performs the best across these metrics, and the Reference Case performs third best out of all of these cases. However, after removal of the duplicative CO_2 metric (far right column), the Reference Plan actually ties with the 85% CO_2 Reduction Case. An argument could also be made that the 2050 Clean Energy metric is another duplicative metric that further considers CO_2 results. However, ORS left that metric in its analysis for now, and considered other aspects of the results. Some of the metrics should be valued more highly than others. For instance, reliability and generator diversity are very important considerations and should be given greater weight in the consideration of the Preferred Plan. Likewise, LNPV cost and Mini-Max Regret are also important and possibly should be given greater weight than other factors. If those factors, as designated with shading in

[84] 2023 IRP, p. 70.
[85] *Id.* at 76.

Table 15, were given more weight, then the Reference Plan would clearly rank highest out of these Build Plans.

Table 15: Build Plan Ranking Analysis

Core Build Plan	30-Year LNPV	Cum. CO_2	2050 CO_2	2050 Clean Energy	Fuel Cost	Gen. Diversity	Reliability	Mini-Max Regret	Cost Range	Average	Average (w/o duplicative CO_2 metric)
Reference	1	4	4	4	4	2	1	2	4	**2.9**	**2.8**
High Fossil Fuel Prices	3	3	3	3	3	5	1	3	3	**3.0**	**3.0**
Zero Carbon Cost	2	5	5	5	5	1	4	1	5	**3.7**	**3.5**
70% CO2 Reduction	4	2	2	1	2	3	5	4	2	**2.8**	**2.9**
85% CO2 Reduction	5	1	1	2	1	4	3	5	1	**2.6**	**2.8**

Based on these results, ORS concludes that it is reasonable to select the Reference Plan as the Preferred Plan.

ORS compared DESC's 2023 IRP Preferred Plan to previous IRP Preferred Plans and a comparison of the key changes through 2035 is reflected in the following table, including retirements and resources proposed to be added.[86]

Table 16: Comparison of Preferred Plans Through 2035

<table>
<tr><th></th><th>2020 Modified IRP Update (RP8)</th><th>2021 IRP Update (RP8)</th><th>2022 IRP Update (Williams 2030)</th><th>2023 IRP Reference</th></tr>
<tr><td>Wateree Retirement Date</td><td colspan="4">Retire in 2028</td></tr>
<tr><td>Williams Retirement Date</td><td colspan="2">Retire in 2028</td><td colspan="2">Retire in 2030</td></tr>
<tr><td>New Combined Cycle MWs</td><td>553</td><td>553</td><td></td><td>662</td></tr>
<tr><td>New CT MWs</td><td>523</td><td>523</td><td>523</td><td></td></tr>
<tr><td>New Solar MWs</td><td>700</td><td>700</td><td>750</td><td>2,775</td></tr>
<tr><td>New Storage MWs</td><td>300</td><td>100</td><td>675</td><td>800</td></tr>
<tr><td>New Solar + Storage MWs</td><td></td><td></td><td>1,350</td><td></td></tr>
</table>

[86] The Company provides the year-by-year description of the reference plan in Appendix E (page 109) and Appendix F (page 123) of the 2023 IRP Report.

The 2023 IRP's Reference Plan (Preferred Plan) selected more renewable resources than were included in previous IRPs and continued the trend of increases in renewable resources compared to the 2020 Modified IRP.

Both the 2022 IRP Update and the 2023 IRP include a new dispatchable resource in 2031, however, instead of a 523 MW CT that was added in the 2022 IRP Update, the 2023 IRP adds a 662 MW shared CC resource.

The Company performed a Supplemental Case in which it replaced the 400 MW battery resource in 2029 with a 262 MW CT and a 100 MW battery storage resource in that same year. The Company referred to this Supplemental Case as the Wateree CT Build Plan. The Company determined that the Supplemental Case was a little more expensive than the Reference Case. DESC concluded from the analysis of the Supplemental Case that it would not make a final Wateree replacement resource decision until after conducting a competitive solicitation process. An RFP is the appropriate venue to evaluate and select specific generation resources. RFP processes provide up-to-date market pricing, resource availability information, and the opportunity to take actionable steps to acquire new capacity.

3. Coal Retirement Study and Wateree and Williams Modeling

DESC's Coal Retirement Study was filed with the Commission on May 16, 2022. DESC stated the Study represented "the first step in a regulatory, permitting, procurement and construction program to allow DESC to retire Wateree and Williams as early as possible in keeping with safe, reliable and affordable service."[87] DESC's study found that under most market conditions, the retirement of the 684 MW Wateree plant by 2028 would reduce costs and lower CO_2 emissions. DESC attributed part of the benefit of retiring Wateree to being able to avoid the costs of complying with ELG requirements. DESC also acknowledged that retirement of Wateree may be risky if the Company was unable to add replacement capacity to the System by the 2028 retirement date. The Company has maintained the same perspective into the 2023 IRP.

As mentioned, the Preferred Plan included a 400 MW battery storage resource being added in 2029 and the Company studied a Supplemental Case in which a 262 MW CT resource plus a 100 MW battery storage resource would be added in 2029. The Preferred Plan and Supplemental Case are close in cost and may require additional consideration beyond the analyses performed as part of the 2023 IRP. The Company indicated two ways in which it would continue to evaluate these options. First, the Company will execute

[87] DESC Coal Retirement Study, Docket No. 2021-192-E, p. 62.

an RFP to identify suitable replacement resources - thermal and storage[88] - and the Company stated it may have to start that process even before the Commission has ruled on the 2023 IRP.[89]

The Company submitted a third TIA study ("2023 TIA") request on January 12, 2023 to "assess the electric transmission costs and construction schedules for the construction of a Shared Resource…"[90] DESC amended the 2023 TIA request on March 28, 2023 to reduce the scope and focus to just the Canadys site. The Company also communicated with stakeholders on June 1, 2023, to explain that on May 19, 2023, it requested a follow-up study to the 2022 TIA Case 2.[91] The results of the latest TIA study were delivered to parties on April 3, 2023. ORS recommends that DESC explain to stakeholders how the results will be used by the Company to decide whether to replace Wateree with a battery storage resource or a combination of a CT and a battery storage resource.

The Company addressed the possibility that it would not be able to complete the acquisition of replacement resources prior to the projected retirement date of Wateree at the end of 2028. The Company stated that in the event of a capacity shortfall, "DESC will proceed with its currently permitted ELG compliance program pathway and may continue operating Wateree into the 2030s to maintain reliable service to customers."[92]

The Company should take every possible cost-effective action it can to avoid the retirement of Wateree without having acquired sufficient replacement capacity to be able to serve customers reliably. The Company determined that ELG upgrades are not economic for customers; therefore, the Company should take necessary actions to ensure replacement resources are available to serve customers.[93]

The Company's Coal Retirement Study concluded it would not be feasible to retire Williams before 2030 as the planned capacity replacement was a combined cycle unit, and building sufficient pipeline capacity and transmission upgrades would not be completed before 2030. The Company stated:

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[88] Response to ORS Information Request 1-12(f).
[89] 2023 IRP, p. 32.
[90] *Id.* at 30.
[91] DESC's June 1, 2023 email to stakeholders, containing DESC's Supplemental Study Request for a Wateree Retirement Modified Case 2 Study request.
[92] 2023 IRP, p. 28.
[93] The Company noted at p. 28 of the 2023 IRP Report that the Company would evaluate whether it could acquire short-term resources for a short-term period, if necessary.

> The 2030 date represents a "best case" planning goal that is subject to much risk and uncertainty. It is important that DESC monitor, review and revise this schedule as retirement planning continues.[94]

No decision regarding the Williams retirement date has to be made now, given the uncertainties that exist, especially in light of plans to retire Wateree at the end of 2028. To make final decisions, the Company should provide the Commission with additional information. First, the Company should continue to complete the TIA studies, which DESC's Electric Transmission Planning Department has already preliminarily determined that substantial transmission upgrades will be needed when the replacement capacity is built. Second, information about pipeline costs and the feasibility of pipeline construction is still unknown and should be evaluated further.

Third, the Company provided little justification for capital additions cost assumptions that were modeled for the Wateree and Williams coal units. This issue became especially apparent when ORS reviewed the Williams 2047 Retirement Case. ORS submitted multiple rounds of discovery to assess the reasonableness of the assumptions the Company used, and ORS determined the Company applied high-cost escalators.[95] DESC provided little support and no benchmarks for the escalation values that were used.[96] ORS recommends the Company provide additional justification for the capital additions costs that were modeled for the Williams and Wateree coals units.

4. All-Source Request for Proposal ("RFP") Procurement Process

In Commission Order No. 2021-429 on DESC's 2020 Modified IRP, Ordering Paragraph 6 required DESC to develop and implement an all-source procurement plan to inform future IRPs. One such RFP was conducted in conjunction with DESC's proposal in Docket No. 2021-93-E to retire thirteen (13) CTs and a natural gas steam turbine unit and replace those units with new capacity resources. DESC pursued the RFP process to replace four CTs and a natural gas steam turbine unit at Urquhart with new capacity, including some that would have black-start capability. The RFP received a mix of supply-side bids, including solar, battery storage, hybrid solar and battery, CTs, and demand response. Some of the bids submitted were self-build proposals. The Company's plan to replace the Wateree coal capacity includes use of an RFP to identify suitable replacement resources.

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[94] DESC 2022 Coal Plants Retirement Study Report, May 16, 2022, p. 62.

[95] Refer to DESC responses to ORS AIR 1-7, 2-6, and 4-13 for the Company's explanation of the capital cost values it used in the analysis.

[96] Response to ORS Information Request 1-7€.

Retirements and New Resource Decisions Recommendations

F1. DESC should provide justification explaining the reasonableness of the significant cost increases associated with generic CT resources in Rebuttal Testimony.

F2. DESC should explain in Rebuttal Testimony why the CC heat rate assumptions are not overly optimistic and confirm this is the technology the Company is considering for the Joint CC unit.

F3. DESC should perform one additional modeling sensitivity of the Reference Case assuming higher battery costs based on the market data provided in the RFP conducted in Docket No. 2021-93-E. The Company should also correct the FO&M costs modeling error identified by Sierra Club. This information should be provided when the Company files Rebuttal Testimony.

F4. DESC should provide additional clarification of the TIA Cases, and further explain how the results will be used to make a final decision about the replacement capacity selected for the Wateree units in Rebuttal Testimony.

F5. DESC should provide additional support for the capital and O&M costs modeled assuming continued operation at Wateree and Williams in Rebuttal Testimony.

G. Other Considerations

1. Bill Impact

In Commission Order No. 2020-832 on DESC's 2020 IRP, the Commission found that it would be reasonable and not overly burdensome for the Company to provide rate and bill impact results of DESC's various portfolios in IRPs, instead of just providing levelized NPV of revenue requirement results. The Company complied with the Commission's requirement in each of the IRPs it has filed since the 2020 Modified IRP, including the 2023 IRP. Appendix H of DESC's 2023 IRP Report contains results of the residential bill impact analysis, and Appendix I shows the retail rate impact results that were derived for the twenty-four (24) cases that the Company evaluated in the 2023 IRP.

In a comparison of the fifteen (15) Core Cases, the results of the residential bill and retail rate impact analyses were consistent, and both analyses showed that the Reference Build Plan and the Zero Carbon Cost Build Plan resulted in nearly the same bill impacts in the Reference Market Scenario and the High Fossil Fuel Market Scenario. The bill impacts of the two Build Plans were similar in the Zero Carbon Cost Market Scenario, but the Zero Carbon Cost Market Build Plan yielded slightly more favorable bill impacts for the Market

Scenario. The Company's results suggest that no matter how the future unfolds, there would be little difference in customer bill impacts if the Company optimized the portfolio with the inclusion of CO_2 costs, versus if the Company optimized the portfolio without including CO_2 costs.

The rate impact analysis for the Load Sensitivity Cases relied on the Reference Case sales forecast even though different load forecasts were used in the load sensitivity cases. The Company acknowledged that different sales forecasts should have been used and plans to address the error in the 2024 Update.[97]

2. PLEXOS Benchmarking

On August 8, 2022, DESC filed an Application for a mid-period adjustment to increase the base fuel costs.[98] In Order No. 2022-860, issued on December 30, 2022 in that docket, the Commission required the Company to provide a report regarding the Company's efforts to benchmark the new PLEXOS production cost model results to actual DESC historic results by no later than February 28, 2023. The Company complied with the Commission requirement and provided a summary report, which included a discussion of the Company's benchmark approach and results. The Company's summary report discussed the results of an analysis the Company performed to study the 2022 historic period using PLEXOS to see how closely PLEXOS could reproduce unit generation and fuel cost results compared to the actual 2022 results.

The Company explained that performing a benchmark can challenging, as some situations may occur in the real world that are hard to factor in to a production cost model. One example that DESC described that incurred in actual system operations required having to constrain the dispatch of coal units to preserve coal inventory to avoid reliability problems.

While there are challenges to producing an accurate benchmark, it is important to conduct benchmarks on a periodic basis, in order to have confidence that the production cost model is reasonably able to simulate the utility's system. Not only is this important for an IRP, in which production cost simulations of future expansion plans are derived, but also for fuel proceedings in which fuel rates are set for a projected period. ORS recommends that the Company be required to conduct benchmark studies on an on-going basis, such as once every three years ahead of Comprehensive IRP proceedings. The Company discuss the results of the benchmarking studies in the Stakeholder Working Group.

[97] Response to ORS Information Request 6-5.
[98] Docket No. 2022-259-E.

3. Risk Analysis

In the Preferred Portfolio Analysis section of this Report, ORS discussed the eight risk metrics that the Company used to analyze the portfolios in order to select the Company's Preferred Plan. With the exception of a concern that the Company actually had nine metrics, in which the ninth was related to CO_2 emissions that was duplicative of another CO_2 metric, the metrics that the Company used in selecting the Preferred Plan are appropriate. However, the Risk Analysis metrics are important and warrant continued discussion within the Stakeholder Working Group.

In ORS's December 19, 2022 Report that reviewed DESC's 2022 IRP Update, ORS recommended DESC discuss in the Stakeholder Working Group ways that it could conduct more robust risk analyses in IRPs.[99] On June 8, 2022, in Stakeholder Meeting VIII, the Company, reviewed risk metrics used by nearby utilities in their expansion planning studies.[100] The ORS recommends the Company should hold additional discussions in the Stakeholder Working Group about risks that should be evaluated, including commodity prices, extreme weather conditions, and the level of DSM. As part of the discussions, the Company should consider the importance of making near-term decisions that feed into the Company's Action Plan.

4. Stakeholder Working Group

The stakeholder process that was required by Order No. 2020-832 has been robust, and the Company has hosted numerous meetings, in which it has posted presentations and session notes on DESC's website. DESC hired CRA to act as the facilitator for the meetings.[101] To date, the Company hosted eleven (11) stakeholder meetings that were attended by representatives from multiple interest groups.

During Sessions IX through XI, held between October 2022 and April 2023, the Company discussed assumptions used by the Company in the 2023 IRP and some of the studies performed in preparation for the 2023 IRP.

Through the stakeholder process there has been important dialog between the Company and interested parties that have included discussions about methodologies and key inputs used in the modeling process. While the parties may not have always reached consensus on issues, the discussions in advance of the Company's IRP filings have allowed for

[99] ORS Review of DESC 2022 IRP Annual Update 2022-9-E p. 33.
[100] https://www.desc-irp-stakeholder-group.com/Portals/0/Documents/MeetingMaterials/DESC_IRP_Advisory_Group_Session_VIII_Minutes_2022.6.pdf, p. 10.
[101] https://www.desc-irp-stakeholder-group.com/default.aspx.

ongoing cooperation, transparency, and information sharing. ORS recommends the Company continue to host the Stakeholder Working Group, and provide updates to the Commission about the activities of the group and the Company's plans to incorporate lessons learned into future IRP filings.

5. Transmission, Distribution, and Integrated System Operations Plans

The Company provided information regarding transmission related topics in the 2023 IRP Report. At page 42 of the Operations Report section, the Company discussed the Transmission Plans and Planning Process, and described North American Electric Reliability Corporation ("NERC") reliability standards that utilities must follow. The Company provided a list of projects that were begun or completed in 2022. The Company noted that whenever transmission lines are rebuilt, wooden structures are replaced with galvanized steel structures for reliability reasons. The Company also included a list of twenty-four (24) transmission projects that are currently ongoing, completed, deferred, or cancelled.

The Company also discussed the TIA studies at page 26 of the 2023 IRP Report. The Company described all of the studies beginning with the 2021 TIA study that was completed in early 2022 through the 2023 TIA study that should be completed in July 2023. Additional information regarding the TIA studies is found in section F3 of this Report regarding Coal Retirements. In addition to the assessment of transmission impacts, assessment of the pipeline capacity availability will be critical for the proposed replacement combined cycle capacity planned to facilitate the retirement of the Williams unit. DESC should update the Commission on the transmission impacts and the natural gas pipeline capacity availability associated with unit retirements and new resource decisions. The Company should file the results of the 2023 TIA Study, including all workpapers and supporting documentation when it becomes available.

Regarding the Distribution and Integrated System Operations Plan, the Company provided information on the Company's effectiveness in providing reliable service to customers. The Company provided the System Average Interruption Duration Index ("SAIDI") score of 78.40 minutes for 2022, which it stated was a historically low level for the System.[102] The Company also reported that in 2022, there were three major storm event that affected the System. The storm impacts were:

[102] 2023 IRP Report, p. 42.

1. Winter Storm Izzy – January 16, 2022, for 52 hours that affected 31,321 customers.
2. Hurricane Ian – September 30, 2022, for 56 hours that affected 206,176 customers.
3. Winter Storm Elliot – December 22, 2022, for 18 hours that affected 53,617 customers.

Winter Storm Elliot was unique in that customers lost power because of insufficient generating capacity at a time when demand was exceptionally high, and DESC, as well as other utilities in the Southeast implemented rolling service interruptions. DESC stated the review of the events of Winter Storm Elliot is ongoing and the Company will work to capture lessons learned to improve reliability in the future.[103]

Finally, the Company provided an update on Automated Metering Infrastructure ("AMI") implementation efforts. The Company stated in 2022, 161,462 electric meters were installed, and the scheduled completion date will be no sooner than January 2024.[104] The Company expects AMI meters, with their direct two-way wireless connection between the Company and the customer, will make it possible for DESC to offer additional DR programs to customers. ICF's DR evaluation for residential and commercial customers identified that in 2037 peak demand reductions due to DR could be as much as 486 MW, 653 MW, and 432 MW for the Reference, High and Low Cases, respectively.[105]

6. Action Plan

In Commission Order on DESC's 2020 IRP, the Commission directed DESC to include:

> In future IRPs a three-year Action Plan identifying and describing the steps it will take to implement its IRP during that three-year period, including but not limited to additional analyses, changes to its methodology, issuance of Requests for Proposals, modifications to its DSM portfolio, and applications for new generating facilities under the Siting Act.[106]

DESC described five categories of Action Plan Items starting at page 92 of the 2023 IRP Report.

[103] *Id.* at 35.
[104] *Id.* at 42.
[105] Direct Testimony of Andrew M. Durkee, Docket No. 2023-9-E, p. 30, ll. 1-2.
[106] Order No. 2020-832, Docket No. 2019-226-E, Ordering Paragraph 11.

Table 17: Action Items

Retirement Planning / RFPs Resource Acquisition	Complete the second and third TIA for the Wateree and Williams retirements.
	Design and conduct a RFP to identify potential replacement resource(s) to support the retirement of Wateree.
	Continue to evaluate the feasibility of planning assumptions as to retirement dates
Peaking Modernization Program	Retire the Parr CT units and continue to execute on the replacement units at Bushy Park and Parr.
	Conclude Urquhart RFP activities
2023 DSM Potential Study	Begin working on modified DSM 5-Year EE Program Plans in collaboration with the EEAG
	Provide updates on new programs and report any changes to the Commission
AMI and Demand Reduction Programs	Complete installation of AMI meters in 2024
	Collect data throughout 2023 to inform the demand response assessment of the 2023 DSM Potential Study
IRP Stakeholder Advisory Group Process	Conduct at least three advisory group meetings in 2023 and 2024 to follow up on the 2023 IRP and prepare for the 2024 and 2025 Update.

DESC complied with the requirement to produce an Action Plan

Other Considerations Recommendations

G1. DESC should be required to conduct production cost model benchmark studies on an on-going basis, such as once every three years ahead of Comprehensive IRP proceedings, and the Company should discuss benchmarking studiy results in the Stakeholder Working Group.

G2. DESC should evaluate additional ways to incorporate robust risk analyses such as assessing portfolios across multiple planning scenarios. As part of this evaluation, the Company should consider the importance of making near-term decisions that feed into the Company’s Action Plan. The Company should discuss this topic in the Stakeholder Working Group.

G3. DESC should update the Commission on the transmission impacts and the natural gas pipeline capacity availability associated with unit retirements and new resource decisions. The Company should file the results of the 2023 TIA Study, including all workpapers and supporting documentation when it becomes available.

Appendix A (Commission Requirements)

The following tables outline the Commission's requirements that impact DESC's IRPs. The Action Items listed in the tables reflect ORS's previously numbered action items.

Table A-1 Requirements by Commission Order No. 2020-832

Action Items	Summary of Requirements by Commission Order No. 2020-832	Section IV - Finding of Facts	Section V - Evidentiary Review	Section VI - Ordering Paragraphs	Adoption Timeline
10	Include additional candidate resource plans, representing the near- term deployment of renewables as described in the testimony of SCSBA Witness Sercy (specifically, the resource plans identified as RP7-A and RP7-B).	4	C	6. a	Modified IRP and 2021 IRP Update
11	Re-model the costs of all candidate resource plans: Use the flexible solar PPA cost assumptions recommended by SCSBA in the Rebuttal Testimony of Witness Sercy, and model 400 MW of Flexible Solar PPAs starting in 2023 with 20-year PPA prices of $34/MWh, $36/MWh, and $38.94/MWh.	8	D.1. (p. 49-50); F. (p. 85-86)	6. b. i	Modified 2020 IRP and 2021 IRP Update
12	Re-model the costs of all candidate resource plans: For battery storage PPAs, use the NREL ATB's Low Storage Cost Case (including capital and fixed O&M 13 costs) with the same 22% ITC safe harbor assumptions employed for solar PV PPAs.	8	D.2. (p. 51-52)	6. b ii	Modified 2020 IRP and 2021 IRP Update
13	Re-model the costs of all candidate resource plans: Correct the incremental flexible solar PPA capacity value assumptions to reflect the ELCC value specific to the existing system penetration level of incremental flexible solar PV.	9	D.5. (p. 58)	6. b. iii	Modified 2020 IRP and 2021 IRP Update
14	Re-model the costs of all candidate resource plans: Assume integration costs of $0.96 / MWh for solar PV, until an updated, Commission-approved methodology for calculating solar integration costs is available.	9	D. 6. . (p. 60-61); F. (p. 86)	6. b. iv	Modified 2020 IRP and 2021 IRP Update

15	Re-model the costs of all candidate resource plans: For ICT, use industry accepted ICT capital cost assumptions, such as NREL.	8	D.4. (p. 55-56)	6. b. v	Modified 2020 IRP and 2021 IRP Update
16	Re-model the costs of all candidate resource plans: For its long-term continuing capital cost de-escalation for both solar PV and BESS, correct its implementation of the two different escalation rates consistent with Mr. Stenclik's surrebuttal testimony.	8	D.3. (p. 53)	6. b. vi.	Modified 2020 IRP and 2021 IRP Update
17	Re-model the costs of all candidate resource plans: Re-run its production cost modeling using the AEO low, reference, and high gas prices described by SCSBA Witness Sercy in his direct testimony, and using the AEO High CO_2 Case, also as detailed in Mr. Sercy's direct testimony.	12	E.2. (p. 69-71)	6. b. vii.	Modified 2020 IRP and 2021 IRP Update
18	Consistent with step 1 as identified in Hearing Exhibit 16, conduct a "rapid assessment" of the cost-effectiveness and achievability of ramping up its current portfolio to achieve at least a 1% level of savings in the years 2022, 2023, and 2024, and include the results of this rapid assessment in its Modified 2020 IRP. The Company will work with the DSM Advisory Group and, if desired, a contractor selected with input from the Advisory Group, in preparing this assessment.	13	E.3. (p. 74-76)	6. e	Modified 2020 IRP
19	Include in its Modified 2020 IRP action steps the Company will take to complete a comprehensive evaluation of the cost-effectiveness and achievability of DSM portfolios ranging from 1% to 2% savings, as identified in steps 3 through 5 of Hearing Exhibit 16.	15	E.3. (p. 74-76)	6. f.	Modified 2020 IRP

Table A-2 Requirements by Commission Order No. 2020-832 (Modified by Order No. 2021-429)

Action Item	Requirements by Commission Order No. 2020-832 (Modified by Order No. 2021-429)	Section VI - Ordering Provisions	Adoption Timeline
8	DESC needs to evaluate near term solar and storage additions in conjunction with its Revised Modified 2020 IRP as previously ordered by the Commission. It is important that potential cost savings for ratepayers can be fully evaluated in subsequent IRPs. Therefore, DESC is ordered to include near term solar and storage in its 2021 IRP Update.	2	Modified 2020 IRP and 2021 IRP Update
9	DESC is required to use "cost effective, reasonable and achievable" as the standard going forward for evaluating the potential for higher savings portfolios in future IRPs and updates beginning with the 2021 IRP Update.	10	Future IRPs and Updates

Table A-3 Requirements Identified by Order No. 2021-429

Action Item(s)	Summary of Requirements by Commission Order No. 2021-429	Section VI - Ordering Provisions	Adoption Timeline
1	DESC is therefore ordered to provide substantive details of the CT Plan and include the CT Plan in its revised modeling in its 2021 IRP Update.	3	2021 IRP Update
2	DESC is ordered to adjust its Reliability Factors in its 2021 IRP Update consistent with Appendix A of the filed "Joint Comments" of Intervenors.	5	2021 IRP Update and Future IRPs
3	DESC shall use Dr. Sercy's Minimax Regrets and Cost Range methodologies in addition to using the "average ranking" approach in order to provide information related to risk using these various approaches.	5	2021 IRP Update and All Future IRPs
4	DESC is ordered to develop and implement an All-Source Procurement Plan in future IRPs.	6	Future IRPs
5	DESC is directed to employ a reasonable levelized cost of saved energy (LCSE) which is comparable with industry standards in conducting its upcoming Market Potential Study and in developing future IRPs starting with the 2021 IRP Update.	7	2021 IRP Update and All Future IRPs
6	DESC is also required to present realistic and levelized DSM costs in all future IRPs starting with the 2021 IRP Update.	8	2021 IRP Update and All Future IRPs
7	DESC is directed to use marginal line losses in the calculation of avoided costs and in the translation of energy savings from the Market Potential Study to energy savings in future IRP modeling beginning with the 2021 IRP Update.	9	2021 IRP Update and All Future IRPs

Table A-4 Requirements by Commission Order Nos. 2020-832 & 2021-429 for Stakeholder Engagement

Action Item(s)	Requirements by Commission Order Nos. 2020-832 & 2021-429 for Stakeholder Engagement	Section V - Finding of Facts	Section VI - Ordering Provisions	Adoption Timeline
20	DESC is also ordered to include load forecasts and the integration of Energy Efficiency impacts with its stakeholders as part of the 2021 IRP Update.	Order No. 2020-832 C.3 (p. 41)	Order No. 2021-429 Ordering Paragraph 8 Order No. 2020-832 Ordering Paragraph 10	2021 IRP Update
21	The Commission concludes that it is reasonable to require DESC to adopt and implement the use of capacity expansion software starting no later than with the development of the 2022 IRP Update. Given the importance of the choice of model, however, the Commission concludes that it is reasonable to require DESC to engage interested parties in this proceeding in a collaborative process to choose capacity expansion model for the 2022 IRP Update and future IRP proceedings. In their deliberations, collaborative members shall consider the criteria set forth in Hearing Exhibit 6, Exhibit AS-2, with particular attention to the criteria numbered 1-7 and 9-12.		Order No. 2020-832 Ordering Paragraph 7.a, 8.a	2022 IRP Update and All Future IRPs
22	DESC is required to perform a comprehensive coal retirement analysis to inform development of its 2022 IRP Update, and to solicit parties' recommendations on guidelines for performing this analysis and approve a set of guidelines prior to DESC's 2022 IRP Update development process via the ongoing IRP Stakeholder Process.		Order No. 2020-832 Ordering Paragraph 7.c,8.i	2022 IRP Update
23	DESC should include DSM and Purchased Power as resource options in the 2021 IRP		Order No. 2020-832	2022 IRP Update

	Update — if achievable — or 2022 IRP Update and future IRPs. It is expected that DESC will consider the input of stakeholders in its evaluation of the purchased power and DSM modeling.		Ordering Paragraph 8.e	and All Future IRPs
24	Prospectively, DESC shall work with stakeholders regarding fair inclusion of solar PV's winter capacity value in the 2021 and 2022 IRP Updates. This should be a good-faith attempt to reach a mutually agreeable value to propose for assignment for PV capacity value in the winter.		Order No. 2020-832 pp. 58	2021 IRP Update and 2022 IRP Update
25	A stakeholder process is an appropriate venue for further refining the risk-adjusted metrics that DESC should apply to future IRPs. The Commission will require DESC to implement the cost range and minimax regret analyses in the Modified 2020 IRP and subsequent updates and will consider more refined and sophisticated risk-adjusted metrics in its 2022 IRP Update.	E.1 (p. 61-64)	Order No. 2020-832 Ordering Paragraph 8.g.	Modified 2020 IRP, All Future IRP Updates, and All Future IRPs
26	The Commission finds persuasive the critiques of DESC's approach to load forecast sensitivities. DESC appears to acknowledge that is an area where its approach to devising its IRP can be improved, but that this is not a fix that can be implemented in time for the Modified 2020 IRP. Therefore, the Commission will require DESC, in its 2022 IRP, to work with stakeholders to develop a wide but plausible range of load forecasts, and ensure that cost modeling captures each resource plan's capabilities to adapt to load that diverges from the base forecast.	E.2 (p. 66,70)	Order No. 2020-832 Ordering Paragraph 8.b.	2022 IRP Update
27	The Commission adopts Steps 3 through 5 as discussed in Witness Hill's Late-Filed Exhibit, and DESC is directed to include this comprehensive evaluation in its 2023 IRP. In its 2023 IRP, DESC must include a comprehensive evaluation of the cost effectiveness and achievability of higher levels of savings, including savings levels of 1.25%, 1.5%, 1.75% and 2%. As outlined in step 3 of the late-filed exhibit, this comprehensive evaluation must consider substantive additions and modifications to the Company' existing DSM portfolio. In implementing this plan, DESC must	E.3 (p. 76)	Order No. 2020-832 Ordering Paragraph 9	2023 IRP

	work with stakeholders, particularly the Advisory Group, and provide opportunities for iterative review, input, and feedback on the Company's analysis and subsequent portfolio development. As part of this presentation in the 2023 IRP, DESC shall include potential incentive options and best practices to achieve the modeled levels of DSM.			
28	DESC is also ordered to include load forecasts and the integration of Energy Efficiency impacts with its stakeholders as part of the 2021 IRP Update.		Order No. 2021-429 Ordering Paragraph 8	2021 IRP Update
			Order No. 2020-832 Ordering Paragraph 10	

Appendix B (Generic Resource Cost Comparison)[107]

Table B-1 (Combustion Turbine Frame)

Combustion Turbine Frame($2022)										
	DESC 2022 IRP Update		DESC 2023 IRP		1803 2023 IRP Frame	EIA AEO 2023 Frame	NREL ATB 2022 Mod Frame	Entergy 2023 IRP CT (M501JAC)	Santee Cooper 2023 IRP	
	Frame 1x	Frame 2x	Frame 1x	Frame 2x					(H-Class)	(F-Class)
Capacity (MW)	262	523	262	523	237	237		365	402	230
Capital Cost ($/kW)	725	725	1,402	1,154	782	867	929	925	699	744
Fixed O&M ($/kW-yr.)	[redacted]				7.92	7.88	24.24	6.66	4.8	7.7
Variable O&M ($/MWh)	[redacted]				5.09	5.06	5.77	14.74	11.42	8.53
Average Heat Rate (MBTU/MWh)	[redacted]				9,905	9,905	9,717	9,165	9,160	10,021

Table B-2 (Combustion Turbine Aero)

Combustion Turbine Aero ($2022)							
	DESC 2022 IRP (Aero 1x)	DESC 2023 IRP (Aero 2x)	Santee Cooper 2023 IRP 1 x LMS100	EIA AEO 2023 Aero	1803 2023 IRP Aero	Entergy 2023 IRP CT (M501JAC)	Entergy 2023 IRP Aero-CT (LMS100PA)
Capacity (MW)	114	114	102	105	105	365	100
Capital Cost ($/kW)	1,760	1,898	1,309	1,428	1,290	925	1,438
Fixed O&M ($/kW-yr.)	[redacted]		17.90	18.35	18.43	6.66	6.47
Variable O&M ($/MWh)	[redacted]		7.63	5.29	5.31	14.74	3.21
Average Heat Rate (MBTU/MWh)	[redacted]		8,957	9,124	9,124	9,165	9,015

[107] Sources used for the following tables: Entergy 2023 IRP, EIA AEO 2023, DESC 2022 IRP Update, DESC 2023 IRP, NREL 2022 ATB, 1803 2023 IRP Docket I-36503 Data Inputs and Assumptions for 1803 Electric Cooperative, Inc., Lazard LCOE 2023, Santee Cooper 2023 IRP; Lazard 2023 assumed to be in $2022.

Table B-3 (Combined Cycle 1x1)

Combined Cycle 1x1 ($2022)									
	DESC 2022 IRP (1x1)	DESC 2023 IRP (1x1)	Santee Cooper 2023 IRP		1803 2023 IRP 1x1	EIA AEO 2023 (Single-Shaft 1x1x1)	Lazard 2023 LCOE (Low) (New Build)	Lazard 2023 LCOE (High) (New Build)	Entergy 2023 IRP Data Filing (1x1)
			1x1 7HA.03 w/ACC	1x1 7FA.05 w/ACC					
Capacity (MW)	553	650	630	357	418	418	550	550	525
Capital Cost ($/kW)	1,857	1,452	1,103	1,702	1,204	1,330	650	1,300	1,156
Fixed O&M ($/kW-yr.)	[redacted]	[redacted]	7.31	11.05	15.94	15.87	10.00	17.00	18.43
Variable O&M ($/MWh)	[redacted]	[redacted]	2.68	3.11	2.88	2.87	2.75	5.00	3.47
Average Heat Rate (MBTU/MWh)	[redacted]	[redacted]	6,136	6,668	6,431	6,431	6,150	6,900	6,375

Table B-4 (Combined Cycle 2x1)

Combined Cycle 2x1 ($2022)								
	DESC 2022 IRP Update (2x1)	DESC 2023 IRP		1803 2023 IRP 2x1	Santee Cooper 2023 IRP 2x1 7HA.03 w/ACC	EIA AEO 2023 (Multi-Shaft 2x2x1)	NREL ATB 2022 F Frame (2x1)	Entergy 2023 IRP Data Filing (2x1)
		2x1	3x1					
Capacity (MW)	1,114	1,325*	1,950	1,083	1,264	1,083	727	1,055
Capital Cost ($/kW)	1,437	1,163	941	1,057	792	1,176	1,058	894
Fixed O&M ($/kW-yr.)	[redacted]	[redacted]	[redacted]	13.73	4.86	13.73	31.60	12.07
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	2.12	2.68	2.10	2.01	3.48
Average Heat Rate (MBTU/MWh)	[redacted]	[redacted]	[redacted]	6,370	6,116	6,370	6,363	6,355

*DESC provides for a 50% sharing of the 2x1 CC Resource as an option

Table B-5 (Off-Shore Wind)

Off-Shore Wind ($2022)									
	DESC 2022 IRP Update	DESC 2023 IRP	Santee Cooper 2023 IRP	EIA AEO 2023	NREL ATB 2022 (Mod)	Entergy 2023 IRP Data Filing	1803 2023 IRP	Lazard 2023 LCOE (Low)	Lazard 2023 LCOE (High)
Capacity (MW)	100	100	1,000	400	1,000	600	50	1,000	1,000
Capital Cost ($/kW)	4,323	4,323	3,952	6,672	2,350	3,620	2,618	3,000	5,000
Fixed O&M ($/kW-yr.)	[redacted]		118.73	123.81	112.63	76.95	117.68	60.00	80.00
Capacity Factor (%)					47%	38%		55%	45%

* See DESC Response to ORS Information Request 3-5 in Docket 2022-9-e

Table B-6 (Solar PV)

Solar ($2022)									
	DESC 2022 IRP Update	DESC 2023 IRP	Santee Cooper 2023 IRP	EIA AEO 2023	NREL ATB 2022 (Mod)	Entergy 2023 IRP Data Filing	1803 2023 IRP	Lazard 2023 LCOE (Low)	Lazard 2023 LCOE (High)
Capacity (MW)	75	75		150	100	100	50	150	150
Capital Cost ($/kW)	1,226	1,240	1,402	1,448	1,187	1,063	1,256	700	1,400
Fixed O&M ($/kW-yr.)	[redacted]		22.24	17.16	21.89	10.52	22.76	7.00	14.00
Capacity Factor (%)					28%	27%			

Table B-7 (Battery Storage)

Battery Storage ($2022)							
	DESC 2022 IRP Update (4 Hour)	DESC 2023 IRP (4 Hour)	Santee Cooper 2023 IRP (4 Hour)	EIA AEO2023 (4 Hour)	NREL ATB 2022 (Mod) (4 Hour)	Entergy 2023 IRP (4 Hour)	1803 2023 IRP
Capacity (MW)	37.5	100		50	60	50/200	50
Capital Cost ($/kW)	1,387	1,459	1,757	1,270	1,420	1,171	1,593
Fixed O&M ($/kW-yr.)	[redacted]		43.92	45.75	35.50	13.39	39.85

Table B-8 (Small Modular Reactor)

Nuclear (Small Modular Reactor) ($2022)								
	DESC 2022 IRP Update	DESC 2023 IRP	Santee Cooper 2023 IRP 12x60 MW	EIA AEO2023	NREL ATB 2022 (Mod)	1803 2023 IRP	Lazard 2023 LCOE (Low) (New Build)	Lazard 2023 LCOE (High) (New Build)
Capacity (MW)	275	274	683	600		600	2,200	2,200
Capital Cost ($/kW)	6,488	12,354	5,986	7,590	7,557	7,892	8,475	13,925
Fixed O&M ($/kW-yr)	[redacted]	[redacted]	95.50	106.92	128.93	107.43	131.50	152.75
Variable O&M ($/MWh)	[redacted]	[redacted]	11.65	3.38	4.07	3.39	4.25	5.00
Average Heat Rate (MBTU/MWh)	[redacted]	[redacted]	10,900	10,447	10,443	10,443	10,450	10,450

Appendix C (Core Build Plan Comparisons)

Reference Build Plan (MW)									
	CC	CT Aero	CT Frame	Solar	Battery	SMR	Off-Shore Wind	Net MW	Reserve Margin Range
2023-2026	0	0	0	150	0	0	0	150	29 - 32
2027-2031	662	0	0	1,425	400	0	0	2,487	21 - 30
2032-2040	0	0	523	2,100	900	0	0	3,523	21 - 29
2041-2050	0	0	523	1,350	300	0	0	2,173	20 - 28
Totals	662	0	1,046	5,025	1,600	0	0	8,333	

High Fossil Fuel Price Build Plan (MW)									
	CC	CT Aero	CT Frame	Solar	Battery	SMR	Off-Shore Wind	Net MW	Reserve Margin Range
2023-2026	0	0	0	300	0	0	0	300	29 -32
2027-2031	662	0	0	1,500	400	0	0	2,562	21 -30
2032-2040	0	0	523	2,700	800	0	0	4,023	20 - 28
2041-2050	0	0	523	2,250	400	0	0	3,173	21 -28
Totals	662	0	1,046	6,750	1,600	0	0	10,058	

Zero Carbon Cost Build Plan (MW)									
	CC	CT Aero	CT Frame	Solar	Battery	SMR	Off-Shore Wind	Net MW	Reserve Margin Range
2023-2026	0	0	0	150	0	0	0	150	29 - 32
2027-2031	662	0	262	1,125	100	0	0	2,149	21 - 30
2032-2040	0	0	0	1,650	800	0	0	2,450	21 - 29
2041-2050	0	0	523	1,350	600	0	0	2,473	20 - 28
Totals	662	0	785	4,275	1,500	0	0	7,222	

70% CO2 Reduction Build Plan (MW)									
	CC	CT Aero	CT Frame	Solar	Battery	SMR	Off-Shore Wind	Net MW	Reserve Margin Range
2023-2026	0	0	0	300	0	0	0	300	29 - 32
2027-2031	1,325	0	262	1,500	300	0	0	3,387	21 - 38
2032-2040	0	0	0	2,700	1,300	0	100	4,100	39 - 46
2041-2050	0	0	0	1,500	0	0	700	2,200	29 - 39
Totals	1,325	0	262	6,000	1,600	0	800	9,987	

85% CO2 Reduction Build Plan (MW)									
	CC	CT Aero	CT Frame	Solar	Battery	SMR	Off-Shore Wind	Net MW	Reserve Margin Range
2023-2026	0	0	0	300	0	0	0	300	29 - 32
2027-2031	1,325	0	262	1,500	300	0	0	3,387	21 - 38
2032-2040	0	0	0	2,700	1,300	268	100	4,368	39 - 46
2041-2050	0	0	0	3,000	0	536	1,000	4,536	40 - 45
Totals	1,325	0	262	7,500	1,600	804	1,100	12,591	